

PG&E CORP

FORM 10-K (Annual Report)

Filed 02/18/05 for the Period Ending 12/31/04

Address	77 BEALE STREET P.O. BOX 770000 SAN FRANCISCO, CA 94177
Telephone	4152677000
CIK	0001004980
Symbol	PCG
SIC Code	4931 - Electric and Other Services Combined
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended December 31, 2004

Or

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from _____ to _____			
Commission File Number	Exact Name of Registrant as specified in its charter	State of Incorporation	IRS Employer Identification Number
1-12609	PG&E CORPORATION	California	94-3234914
1-2348	PACIFIC GAS AND ELECTRIC COMPANY	California	94-0742640
Pacific Gas and Electric Company 77 Beale Street P.O. Box 770000 San Francisco, California (Address of principal executive offices) 94177 (Zip Code) (415) 973-7000 (Registrant's telephone number, including area code)		PG&E Corporation One Market, Spear Tower Suite 2400 San Francisco, California (Address of principal executive offices) 94105 (Zip Code) (415) 267-7000 (Registrant's telephone number, including area code)	

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
PG&E Corporation Common Stock, no par value	New York Stock Exchange and Pacific Exchange
Pacific Gas and Electric Company First Preferred Stock, cumulative, par value \$25 per share: Redeemable: 7.04%, 5% Series A, 5%, 4.80%, 4.50%, 4.36% Mandatorily Redeemable: 6.57%, 6.30% Nonredeemable: 6%, 5.50%, 5%	American Stock Exchange and Pacific Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

PG&E Corporation ☐

Pacific Gas and Electric Company ☒

Indicate by check mark whether the registrant is an accelerated filer (as defined in Exchange Act Rule 12b-2):

PG&E Corporation	Yes ☒	No ☐
Pacific Gas and Electric Company	Yes ☐	No ☒

Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2004, the last business day of the second fiscal quarter:

PG&E Corporation Common Stock	\$11,183 million
Pacific Gas and Electric Company Common Stock	Wholly owned by PG&E Corporation
Common Stock outstanding as of February 11, 2005:	
PG&E Corporation:	396,487,454 (excluding shares held by a wholly owned subsidiary)
Pacific Gas and Electric Company:	Wholly owned by PG&E Corporation

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved.

Designated portions of the combined Annual Report to Shareholders for the year ended December 31, 2004	Part I (Item 1), Part II (Items 5, 6, 7, 7A, 8 and 9A), Part IV (Item 15)
Designated portions of the Joint Proxy Statement relating to the 2005 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

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UNITS OF MEASUREMENT

1 Kilowatt (kW)	=	One thousand watts
1 Kilowatt-Hour (kWh)	=	One kilowatt continuously for one hour
1 Megawatt (MW)	=	One thousand kilowatts
1 Megawatt-Hour (MWh)	=	One megawatt continuously for one hour
1 Gigawatt (GW)	=	One million kilowatts
1 Gigawatt Hour (GWh)	=	One gigawatt continuously for one hour
1 Kilovolt (kV)	=	One thousand volts
1 MVA	=	One megavolt ampere
1 Mcf	=	One thousand cubic feet
1 MMcf	=	One million cubic feet
1Bcf	=	One billion cubic feet
1MDth	=	One thousand decatherms

PART I

Item 1. *Business.*

GENERAL

Corporate Structure and Business

PG&E Corporation, incorporated in California in 1995, is an energy-based holding company that conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages primarily in the businesses of electricity and natural gas distribution, electricity generation, procurement and transmission, and natural gas procurement, transportation and storage. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. During 2004, PG&E Corporation also owned National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, Inc., which engaged in electricity generation and natural gas transportation in the United States, or U.S.

The Utility

The Utility served approximately 4.9 million electricity distribution customers and approximately 4.1 million natural gas distribution customers at December 31, 2004. The Utility had approximately \$34.3 billion of assets at December 31, 2004, and generated revenues of approximately \$11.1 billion in 2004. Its revenues are generated mainly through the sale and delivery of electricity and natural gas. The Utility is regulated primarily by the California Public Utilities Commission, or the CPUC, and the Federal Energy Regulatory Commission, or the FERC.

On April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, in the U.S. Bankruptcy Court for the Northern District of California. In March 2004, in anticipation of its exit from Chapter 11, the Utility issued \$6.7 billion of first mortgage bonds, or First Mortgage Bonds, and, together with its consolidated subsidiaries, entered into \$2.9 billion of credit facilities. On April 12, 2004, the Utility's plan of reorganization under Chapter 11 became effective. On this date, the effective date, the Utility emerged from Chapter 11. On the effective date, the Utility paid all valid claims, deposited funds into escrow accounts for the payment of disputed claims upon their resolution, reinstated certain obligations, and paid other obligations.

The Utility's plan of reorganization incorporated the terms of the settlement agreement approved by the CPUC on December 18, 2003, and entered into among the CPUC, the Utility and PG&E Corporation on December 19, 2003, to resolve the Utility's Chapter 11 proceeding, or Settlement Agreement. The parties agreed that the bankruptcy court has jurisdiction over the parties for all purposes relating to enforcement of the Settlement Agreement over its nine-year term, the plan of reorganization, and the bankruptcy court's December 22, 2003 order confirming the plan of reorganization, or confirmation order. Although the Utility's operations are no longer subject to the oversight of the bankruptcy court, the bankruptcy court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Settlement Agreement, (2) the plan of reorganization, and (3) the confirmation order. In addition, the bankruptcy court retains jurisdiction to resolve remaining disputed claims.

As discussed further below under Item 3. Legal Proceedings, appeals of the confirmation order and petitions seeking review of the CPUC's approval of the Settlement Agreement remain pending. Under applicable federal precedent, once the plan of reorganization has been "substantially consummated," any pending appeals of the confirmation order should be dismissed. If, notwithstanding this federal precedent, the bankruptcy court's confirmation order or the Settlement Agreement is

subsequently overturned or modified, PG&E Corporation and the Utility's financial condition and results of operations could be materially adversely affected.

The Utility's plan of reorganization and the Settlement Agreement are discussed in Management's Discussion and Analysis of Financial Condition and Results of Operations, or the MD&A, and in Note 2 of the Notes to the Consolidated Financial Statements in PG&E Corporation's and the Utility's Combined 2004 Annual Report to Shareholders, or the Annual Report, which is incorporated by reference into this report.

NEGT

NEGT was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. On July 8, 2003, NEGТ and certain of its subsidiaries filed voluntary petitions for relief under the provisions of Chapter 11 in the U.S. Bankruptcy Court for the District of Maryland, Greenbelt Division. For the reasons described in Note 5, PG&E Corporation considers NEGТ to be an abandoned asset under Statement of Financial Accounting Standards, or SFAS, "Accounting for Impairment or Disposal of Long-Lived Assets," or SFAS No. 144, and, as a result, the operations of NEGТ prior to July 8, 2003 and for all prior periods, are reflected as discontinued operations in the Consolidated Financial Statements. In addition, as discussed in Note 4, effective July 8, 2003, PG&E Corporation no longer consolidated the earnings and losses of NEGТ or its subsidiaries and began accounting for its ownership interest in NEGТ using the cost method, under which PG&E Corporation's investment in NEGТ is reflected as a single amount on the Condensed Consolidated Balance Sheet of PG&E Corporation. On October 29, 2004, NEGТ's plan of reorganization became effective and NEGТ emerged from Chapter 11, at which time PG&E Corporation's equity interest in NEGТ was cancelled. For a discussion of the effect of the cancellation of PG&E Corporation's equity ownership in NEGТ on PG&E Corporation's earnings from discontinued operations for the quarter and year ended December 31, 2004, see MD&A.

Corporate and Other Information

The principal executive office of PG&E Corporation is located at One Market, Spear Tower, Suite 2400, San Francisco, California 94105, and its telephone number is (415) 267-7000. The principal executive office of the Utility is located at 77 Beale Street, P.O. Box 770000, San Francisco, California 94177, and its telephone number is (415) 973-7000. PG&E Corporation and the Utility file various reports with the Securities and Exchange Commission, or the SEC. These reports, including Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Sections 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended, are available free of charge on both PG&E Corporation's website, www.pge-corp.com, and the Utility's website, www.pge.com. The information contained on these websites is not incorporated by reference into this Annual Report on Form 10-K and should not be considered part of this report.

Employees

At December 31, 2004, PG&E Corporation and its subsidiaries had approximately 20,200 employees, including approximately 20,000 employees of the Utility. Of the Utility's employees, approximately 13,700 are covered by collective bargaining agreements with three labor unions: the International Brotherhood of Electrical Workers, Local 1245, AFL-CIO, or IBEW; the Engineers and Scientists of California, IFPTE Local 20, AFL-CIO and CLC, or ESC; and the Service Employees International Union, Local 24/7, or SEIU. The ESC and IBEW collective bargaining agreements expire on December 31, 2007. The SEIU collective bargaining agreement expires on February 28, 2008.

Forward-Looking Statements and Risk Factors

This combined Annual Report on Form 10-K, including the portions of the Annual Report incorporated by reference, contains forward-looking statements that are necessarily subject to various risks and uncertainties the realization or resolution of which are outside of management's control. These statements are based on current expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts at the time the statements were made. These forward-looking statements are identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "might," "will," "should," "would," "could," "goal," "potential" and similar expressions. Although PG&E Corporation and the Utility are not able to predict all the factors that may affect future results, some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include:

Appeals of the Utility's Plan of Reorganization and Settlement Agreement

- The timing and resolution of the petitions for review that were filed in the California Court of Appeal for the first Appellate District, or the California Court of Appeal, seeking review of the CPUC's approval of the Settlement Agreement; and
- The timing and resolution of the pending appeals of the confirmation order.

Operating Environment

- Unanticipated changes in operating expenses or capital expenditures, which may affect the Utility's ability to earn its authorized rate of return;
- The level and volatility of wholesale electricity and natural gas prices and supplies, the Utility's ability to manage and respond to the levels and volatility successfully and the extent to which the Utility is able to timely recover increased costs related to such volatility;
- Weather, storms, earthquakes, fires, floods, other natural disasters, explosions, accidents, mechanical breakdowns and other events or hazards that affect demand, result in power outages, reduce generating output, or cause damage to the Utility's assets or operations or those of third parties on which the Utility relies;
- Unanticipated population growth or decline, changes in market demand and demographic patterns, and general economic and financial market conditions, including unanticipated changes in interest or inflation rates, and the extent to which the Utility is able to timely recover its costs in the face of such events;
- The operation of the Utility's Diablo Canyon nuclear power plant, or Diablo Canyon, which exposes the Utility to potentially significant environmental costs and capital expenditure outlays and, to the extent the Utility is unable to increase its spent fuel storage capacity by 2007 or find an alternative depository, the risk that the Utility may be required to close Diablo Canyon and purchase electricity from more expensive sources;
- Actions of credit rating agencies;
- Significant changes in the Utility's relationship with its employees, the availability of qualified personnel and the potential adverse effects if labor disputes were to occur; and
- Acts of terrorism.

Legislative and Regulatory Environment and Pending Litigation

- The impact of current and future ratemaking actions of the CPUC, including the risk of material differences between forecasted costs used to determine rates and actual costs incurred;
- Whether the assumptions and forecasts underlying the Utility's CPUC-approved long-term electricity procurement plan prove to be accurate, the terms and conditions of the generation or procurement commitments the Utility enters into in connection with its plan, and the extent to which the Utility is able to recover the costs it incurs in connection with these commitments, and the extent to which a failure to perform by any of the counterparties to the Utility's electricity purchase contracts or the DWR contracts allocated to the Utility's customers affects the Utility's ability to meet its obligations or to recover its costs;
- Prevailing governmental policies and legislative or regulatory actions generally, including those of the California legislature, the U.S. Congress, the CPUC, the FERC, and the Nuclear Regulatory Commission, or the NRC, with regard to the Utility's allowed rates of return, industry and rate structure, recovery of investments and costs, acquisitions and disposal of assets and facilities, treatment of affiliate contracts and relationships, and operation and construction of facilities;
- The extent to which the CPUC or the FERC delays or denies recovery of the Utility's costs, including electricity purchase costs, from customers due to a regulatory determination that such costs were not reasonable or prudent or for other reasons resulting in write-offs of regulatory balancing accounts;
- How the CPUC administers the capital structure, stand-alone dividend and first priority conditions of the CPUC's decisions permitting the establishment of holding companies for the California investor-owned electric utilities;
- The terms under which the CPUC authorizes the Utility to issue debt and equity in the future, and in particular the extent to which the conditions adopted by the CPUC, such as those contained in the CPUC's general financing authorization decision issued on October 28, 2004 (under which the Utility is authorized to issue debt and preferred stock in the future within certain amounts and for specific purposes) limit the Utility's ability to issue debt in the future;
- Whether the Utility is in compliance with all applicable rules, tariffs and orders relating to electricity and natural gas utility operations, and the extent to which a finding of non-compliance could result in customer refunds, penalties or other non-recoverable expenses;
- Whether the Utility is required to incur material costs or capital expenditures or curtail or cease operations at affected facilities to comply with existing and future environmental laws, regulations and policies; and
- The outcome of pending litigation.

Competition

- Increased competition as a result of the takeover by condemnation of the Utility's distribution assets, duplication of the Utility's distribution assets or service by local public utilities, and other forms of competition that may result in stranded investment capital, decreased customer growth, loss of customer load and additional barriers to cost recovery; and
- The extent to which the Utility's distribution customers switch between purchasing electricity from the Utility and from alternate energy service providers as direct access customers, the extent to which cities, counties and others in the Utility's service territory begin directly serving the Utility's customers, and the extent to which the Utility's customers become self-generators, results in stranded generating asset costs and non-recoverable procurement costs.

For a further discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future results of operations and financial condition, see the section of the Annual Report titled "Risk Factors."

Electric Utility Operations

Electricity Distribution Operations

The Utility's electricity distribution network extends throughout all or a part of 46 of California's 58 counties, comprising most of northern and central California. The Utility's network consists of 123,054 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead). There are 89 transmission substations and 48 transmission-switching stations. A transmission substation is a fenced facility where voltage is transformed from one transmission voltage level to another. There are 610 distribution substations and 118 low voltage distribution substations. There are 290 combined transmission and distribution substations. Combined transmission and distribution substations have both transmission and distribution transformers.

The Utility's distribution network interconnects to the Utility's electricity transmission system at 1,118 points. This interconnection between the Utility's distribution network and the transmission system typically occurs at distribution substations where transformers and switching equipment reduce the high-voltage transmission levels at which the electricity transmission system transmits electricity, ranging from 500 kV to 60 kV, to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility's customers. The distribution substations serve as the central hubs of the Utility's electricity distribution network and consist of transformers, voltage regulation equipment, protective devices and structural equipment. Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users. In some cases, the Utility sells electricity from its distribution lines or facilities to entities, such as municipal and other utilities, that then resell the electricity.

2004 Electricity Deliveries

The following table shows the percentage of the Utility's total 2004 electricity deliveries represented by each of its major customer classes:

Total 2004 Electricity Delivered: 82,907 GWhs

Agricultural and Other Customers	8%
Industrial Customers	18%
Residential Customers	35%
Commercial Customers	39%

Electricity Distribution Operating Statistics

The following table shows certain of the Utility's operating statistics from 2000 to 2004 for electricity sold or delivered, including the classification of sales and revenues by type of service.

	2004	2003	2002	2001	2000
Customers (average for the year):					
Residential	4,366,897	4,286,085	4,171,365	4,165,073	4,071,794
Commercial	509,501	493,638	483,946	484,430	471,080
Industrial	1,339	1,372	1,249	1,368	1,300
Agricultural	80,276	81,378	78,738	81,375	78,439
Public street and highway lighting	27,176	26,650	24,119	23,913	23,339
Other electric utilities	3	4	5	5	8
Total	4,985,192	4,889,127	4,759,422	4,756,164	4,645,960
Deliveries (in GWh):(1)					
Residential	29,453	29,024	27,435	26,840	28,753
Commercial	32,268	31,889	31,328	30,780	31,761
Industrial	14,796	14,653	14,729	16,001	16,899
Agricultural	4,300	3,909	4,000	4,093	3,818
Public street and highway lighting	2,091	605	674	418	426
Other electric utilities	28	76	64	241	266
Subtotal	82,936	80,156	78,230	78,373	81,923
DWR	(19,938)	(23,554)	(21,031)	(28,640)	—
Total non-DWR electricity	62,998	56,602	57,199	49,733	81,923
Revenues (in millions):					
Residential	\$ 3,718	\$ 3,671	\$ 3,646	\$ 3,396	\$ 3,062
Commercial	4,179	4,440	4,588	4,105	3,110
Industrial	1,204	1,410	1,449	1,554	1,053
Agricultural	491	522	520	525	420
Public street and highway lighting	71	69	73	60	43
Other electric utilities	22	24	10	39	26
Subtotal	9,685	10,136	10,286	9,679	7,714
DWR	(1,933)	(2,243)	(2,056)	(2,173)	—
Direct access credits	—	(277)	(285)	(461)	(1,055)
Miscellaneous(2)	(248)	(52)	193	244	202
Regulatory balancing accounts	363	18	40	37	(7)
Total electricity operating revenues	\$ 7,867	\$ 7,582	\$ 8,178	\$ 7,326	\$ 6,854
Other Data:					
Average annual residential usage (kWh)	6,744	6,772	6,577	6,444	7,062
Average billed revenues (cents per KWh):					
Residential	12.62	12.65	13.29	12.65	10.65
Commercial	12.95	13.92	14.65	13.34	9.79
Industrial	8.14	9.62	9.84	9.71	6.23
Agricultural	11.41	13.35	13.00	12.83	11.00
Net plant investment per customer	\$ 2,790	\$ 2,689	\$ 2,105	\$ 2,018	\$ 1,969

(1) These amounts include electricity provided to direct access customers who procure their own supplies of electricity.

(2) Miscellaneous revenues in 2003 include a \$125 million reduction due to refunds to electricity customers from generation-related revenues in excess of generation-related costs.

Electricity Resources

The following table shows the percentage of the Utility's total sources of electricity for 2004 represented by each major electricity resource:

Owned generation (nuclear, fossil fuel-fired and hydroelectric facilities)	33%
DWR	25%
Qualifying Facilities/Renewables	23%
Irrigation Districts	5%
Other Power Purchases	14%

The Utility is required to dispatch all of the electricity resources within its portfolio, including electricity provided under DWR contracts, in the most cost-effective way. To the extent the Utility's electricity resources are not sufficient to meet the demand of the Utility's customers, the Utility purchases the electricity from the wholesale electricity market. At other times, least-cost dispatch requires the Utility to schedule more electricity than is necessary to meet its retail load and to sell this additional electricity on the wholesale electricity market. The Utility typically schedules excess electricity when the expected electricity sales proceeds exceed the variable costs to operate a generation facility or buy electricity on an optional contract.

Owned Generation Facilities

At December 31, 2004, the Utility owned and operated the following generation facilities, all located in California, listed by energy source:

Generation Type	County Location	Number of Units	Net Operating Capacity (MW)
Nuclear:			
Diablo Canyon	San Luis Obispo	2	2,174
Hydroelectric:			
Conventional	16 counties in northern and central California	107	2,684
Helms pumped storage	Fresno	3	1,212
Hydro electric subtotal		110	3,896
Fossil fuel:			
Humboldt Bay(1)	Humboldt	2	105
Hunters Point(2)	San Francisco	2	215
Mobile turbines	Humboldt	2	30
Fossil fuel subtotal		6	350
Total		118	6,420

- (1) The Humboldt Bay facilities consist of a retired nuclear generation unit, or Humboldt Bay Unit 3, and two operating fossil fuel-fired plants.
- (2) In July 1998, the Utility reached an agreement with the City and County of San Francisco regarding the Utility's Hunters Point fossil fuel-fired plant, which has been designated as a "must run" facility by the California Independent System Operator, or ISO, to support system reliability. The agreement expresses the Utility's intention to retire the plant when it is no longer needed.

Diablo Canyon Power Plant. The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, each capable of generating up to approximately 1,087 MW of electricity. Unit 1 began commercial operation in May 1985 and the operating license for this unit expires in September 2021. Unit 2 began commercial operation in March 1986 and the operating license for this unit expires in April 2025. For the ten-year period ended December 31, 2004, the Utility's Diablo Canyon power plant achieved an average overall capacity factor of approximately 88.4%.

The following table outlines the Diablo Canyon power plant's refueling schedule for the next five years. The Diablo Canyon power plant refueling outages are typically scheduled every 16 to 21 months. The average length of a refueling outage over the last five years has been approximately 46 days. It is anticipated, however, that additional work will be required during future scheduled outages leading up to the replacement of the steam generators in Unit 2 in 2008 and in Unit 1 in 2009. The capital expenditures necessary to complete these projects are discussed further in the MD&A. This additional work will lengthen the forecasted outage durations to the time periods shown below. The table below shows outages of up to 45 days to accommodate non-routine tasks, such as expanded steam generator inspection and repair and low-pressure turbine rotor replacement. Outages of up to 80 days are scheduled for steam generator replacements. The actual refueling schedule and outage duration will depend on the scope of the work required for a particular outage and other factors.

	2005	2006	2007	2008	2009
Unit 1					
Refueling	October	—	April	—	January
Duration (days)	45	—	35	—	80
Startup	December		June		March
Unit 2					
Refueling		April		February	October
Duration (days)	—	45	—	80	25
Startup	—	June	—	April	October

The Utility has several types of nuclear insurance for its Diablo Canyon power plant and Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to \$3.24 billion per incident. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged outage, the Utility may be required to pay an additional premium of up to \$42.5 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. If one or more acts of domestic terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member within a 12-month period, the maximum recovery under all those nuclear insurance policies may not exceed \$3.24 billion plus the additional amounts recovered by NEIL for these losses from reinsurance. Under the Terrorism Risk Insurance Act of 2002, NEIL would be entitled to receive substantial proceeds from reinsurance coverage for an act caused by foreign terrorism. The Terrorism Risk Insurance Act of 2002 expires on December 31, 2005.

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to \$10.8 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of \$300 million for the Diablo Canyon power plant. The balance of the \$10.8 billion of liability protection is covered by a loss-sharing program (secondary financial protection) among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of nuclear reactors that are licensed to operate, designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs in excess of \$300 million, then the Utility may be responsible for up to

\$100.6 million per reactor, with payments in each year limited to a maximum of \$10 million per incident until the Utility has fully paid its share of the liability. Since the Diablo Canyon power plant has two nuclear reactors each with a rated capacity of over 100 MW, the Utility may be assessed up to \$201.2 million per incident, with payments in each year limited to a maximum of \$20 million per incident. Although the Price-Anderson Act expired on December 31, 2003, coverage continues to be provided to all licensees, including the Diablo Canyon power plant, which had coverage before December 31, 2003. Congress may address renewal of the Price Anderson Act in future energy legislation.

In addition, the Utility has \$53.3 million of liability insurance for the retired nuclear generating unit at the Humboldt Bay power plant and has a \$500 million indemnification from the NRC for public liability arising from nuclear incidents covering liabilities in excess of the \$53.3 million of liability insurance.

Hydroelectric Generation Facilities. The Utility's hydroelectric system consists of 110 generating units at 68 powerhouses, including a pumped storage facility, with a total generating capacity of 3,896 MW. The system includes 99 reservoirs, 76 diversions, 174 dams, 184 miles of canals, 44 miles of flumes, 135 miles of tunnels, 19 miles of pipe and 5 miles of natural waterways. The system also includes water rights as specified in 86 permits or licenses and 163 statements of water diversion and use. With the exception of three non-jurisdictional powerhouses, all of the Utility's powerhouses are licensed by the FERC. Pursuant to the Federal Power Act, the term of a hydroelectric project license issued by the FERC is between 30 and 50 years. In the last four years, the Utility has received six renewed hydroelectric project licenses from the FERC totaling 699 MW. Licenses associated with approximately 879 MW now in relicensing have expired; these projects are being operated on automatically renewed annual licenses pending issuance of renewed licenses. Within the next four years, licenses associated with another 50 MW will expire. Licenses associated with approximately 2,959 MW expire between 2009 and 2043.

DWR Power Purchases

In January 2001, because of the deteriorating credit conditions of the California investor-owned electric utilities, the State of California authorized the DWR to purchase electricity to meet the portion of the demand of the utilities' customers, plus applicable reserve margins, not satisfied from their own generation facilities and existing electricity contracts. California Assembly Bill 1X, or AB 1X, passed in February 2001, authorized the DWR to enter into contracts for the purchase of electricity and to issue revenue bonds to finance electricity purchases. The Utility and the other California investor-owned electric utilities act as the billing and collection agent for the DWR's sales of electricity to retail customers.

On September 19, 2002, the CPUC issued a decision allocating electricity from 19 of the DWR's contracts to the Utility's customers. In January 2003, the Utility became responsible for scheduling and dispatching the electricity subject to the 19 DWR allocated contracts on a least-cost basis and for many administrative functions associated with those contracts. The contracts terminate at various times through 2012 and consist of must-take and capacity charge contracts. During 2004, a total average capacity of approximately 2,700 MW of the electricity under the DWR allocated contracts is subject to "must take" provisions that require the DWR to take and pay for the electricity regardless of whether the electricity is needed. A total average capacity for 2004 of approximately 1,200 MW of the electricity under the DWR allocated contracts is subject to provisions that require the DWR to pay a capacity charge, but do not require the purchase of electricity unless that electricity is dispatched and delivered. Electricity from the DWR allocated contracts represented approximately 22% of the Utility's total sources of electricity in 2004.

The DWR is currently legally and financially responsible for these contracts. The DWR has stated publicly that it intends to transfer full legal title to, and responsibility for, the DWR power purchase contracts to the California investor-owned electric utilities as soon as possible. However, the DWR power purchase contracts cannot be transferred to the Utility without the consent of the CPUC. The Settlement Agreement provides that the CPUC will not require the Utility to accept an assignment of, or to assume legal or financial responsibility for, the DWR power purchase contracts unless each of the following conditions has been met:

- After assumption, the Utility's issuer rating by Moody's Investors Service, or Moody's, will be no less than A2 and the Utility's long-term issuer credit rating by Standard & Poor's, or S&P, will be no less than A;
- The CPUC first makes a finding that the DWR power purchase contracts to be assumed are just and reasonable; and
- The CPUC has acted to ensure that the Utility will receive full and timely recovery in its retail electricity rates of all costs associated with the DWR power purchase contracts to be assumed without further review.

The Settlement Agreement does not limit the CPUC's discretion to review the prudence of the Utility's administration and dispatch of the assumed DWR power purchase contracts consistent with applicable law.

Third Party Power Purchase Agreements

Qualifying Facility Power Purchase Agreements

The Utility is required by CPUC decisions to purchase energy and capacity from independent power producers that are qualifying facilities under the Public Utility Regulatory Policies Act of 1978, or PURPA. To implement PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with qualifying facilities and approved the applicable terms, conditions, prices, and eligibility requirements. These agreements require the Utility to pay for energy and capacity. Energy payments are based on the qualifying facility's actual electrical output and CPUC-approved energy prices, while capacity payments are based on the qualifying facility's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the qualifying facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

As of December 31, 2004, the Utility had agreements with 300 qualifying facilities for approximately 4,300 megawatts, or MW, that are in operation. Agreements for approximately 3,950 MW expire at various dates between 2005 and 2028. Qualifying facility power purchase agreements for approximately 350 MW have no specific expiration dates and will terminate only when the owner of the qualifying facility exercises its termination option. The Utility also has power purchase agreements with approximately 50 inoperative qualifying facilities. The total of approximately 4,300 MW consists of approximately 2,600 MW from cogeneration projects, 700 MW from wind projects and 1,000 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar and hydroelectric.

On January 22, 2004, the CPUC ordered the California investor-owned electric utilities to allow owners of qualifying facilities with certain power purchase agreements expiring before the end of 2005 to extend these contracts for five years with modified pricing terms. As of December 31, 2004, thirteen qualifying facilities had entered into such five-year contract extensions. Qualifying facility power purchase agreements accounted for approximately 21% of the Utility's 2004 electricity sources, approximately 20% of the Utility's 2003 electricity sources, and approximately 25% of the Utility's 2002

electricity sources. No single qualifying facility accounted for more than 5% of the Utility's 2004, 2003, or 2002 electricity sources.

There are proceedings pending at the CPUC that may impact both the amount of payments to qualifying facilities and the number of qualifying facilities holding power purchase agreements with the Utility. The CPUC will address whether certain payments for short-term power deliveries required by the power purchase agreements comply with the pricing requirements of the PURPA. The CPUC is also considering whether to require the California investor owned electric utilities to enter into new power purchase agreements with existing qualifying facilities with expiring power purchase agreements and with newly-constructed qualifying facilities. PG&E Corporation and the Utility are unable to estimate the outcome of these proceedings.

Irrigation Districts and Water Agencies

The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts' and water agencies' debt service requirements, regardless if any hydroelectric power is supplied, and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2005 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 4% of 2004 electricity sources, approximately 5% of 2003 electricity sources, and approximately 4% of 2002 electricity sources.

Other Power Purchase Agreements

Electricity Purchases to Satisfy the Residual Net Open Position

In 2004, the Utility continued buying electricity to meet its residual net open position. During 2004, more than 10,000 Gigawatt hours, or GWh of energy was bought and sold in the wholesale market to manage the Utility's 2004 residual net short/open position. Most of the Utility's contracts entered into in 2004 had terms of less than one year. In 2004, the Utility both submitted and requested bids in competitive solicitations to meet intermediate and long-term needs and anticipates procuring electricity under contracts with multi-year terms beginning in 2005.

Renewable Energy Contracts

California law requires that, beginning in 2003, each California retail seller of electricity, except for municipal utilities, must increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year, the annual procurement target, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. The Utility was excused from meeting its annual procurement target under the current law in 2003 and 2004 due to its Chapter 11 proceeding. With its exit from Chapter 11, as of January 1, 2005, the Utility is no longer exempt from complying with its annual procurement target. To meet the 20% goal by the end of 2017, the Utility estimates that it will need to purchase 700-800 GWh of electricity from renewable resources each year. During 2003 and 2004, the Utility entered into several new renewable power purchase contracts that will help the Utility meet its goals. The Utility also is conducting negotiations with several renewable energy providers pursuant to a request for offers made by the Utility in July 2004 that should result in the Utility entering into a number of new renewable contracts in 2005. In January 2005, the California Senate introduced a bill proposing to require the goal to be met by the end of 2010 instead of 2017. The CPUC also has suggested that the 20% goal be met by 2010. The Utility estimates that the accelerated goal would require the Utility to increase the amount of its annual renewable energy purchases to approximately 800-900 GWh. Based on the medium load scenario in the Utility's long-term electricity procurement plan, the Utility believes that it can meet the accelerated goal.

In 1967, the Utility and the Western Area Power Administration, or WAPA, entered into several long-term power contracts governing the interconnection of the Utility's and WAPA's electricity transmission systems, the use of the Utility's electricity transmission and distribution system by WAPA, and the integration of the Utility's and WAPA's customer demands and electricity resources. The contracts gave the Utility access to WAPA's excess hydroelectric power and obligated the Utility to provide WAPA with electricity when its own resources were not sufficient to meet its requirements. In recent years the pricing formula under the contract often resulted in the Utility selling power to WAPA at prices that were below market. On December 3, 2004, the FERC approved termination of the contracts as of January 1, 2005, and approved the new service contracts that WAPA and the Utility executed in October 2004. Under the new contracts, which became effective on January 1, 2005, the Utility no longer provides any electric power or transmission services to WAPA but continues to provide wholesale distribution service.

For more information regarding the Utility's power purchase contracts, see Note 12 of the Notes to the Consolidated Financial Statements of the Annual Report.

Electricity Transmission

At December 31, 2004, the Utility owned 18,610 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV and transmission substations with a capacity of 46,036 MVA. Electricity is transmitted across these lines and substations and is then distributed to customers through 123,054 circuit miles of distribution lines and substations with a capacity of 24,877 MVA. In 2004, the Utility delivered 82,936 GWh to its customers, including 9,210 GWh delivered to direct access customers. The Utility is interconnected with electric power systems in the Western Electricity Coordinating Council which includes 14 western states, Alberta and British Columbia, Canada, and parts of Mexico.

In connection with electricity industry restructuring, the California investor-owned electric utilities relinquished control, but not ownership, of their transmission facilities to the ISO, in 1998. The FERC has jurisdiction over these transmission facilities, and the revenue requirements and rates for transmission service are set by the FERC. The ISO, which is regulated by the FERC, controls the operation of the transmission system and provides open access transmission service on a nondiscriminatory basis. The ISO also is responsible for maintaining the reliability of the transmission system.

The Utility has been working closely with the ISO to continue expanding the capacity on the Utility's electric transmission system. In December 2004, construction was completed on a new 500 kV line to expand one segment of the transmission system, known as Path 15, which is located in the southern portion of the Utility's service area, and serves as part of the primary transmission path between northern California and southern California. The improvements are intended to mitigate transmission constraints in this area. The Utility has interconnected the new 500 kV line at its existing substations at the line terminals and reconfigured its 230 kV and 115 kV facilities in the area to support a higher transfer capability through this section of the grid. This new 500 kV line became operational in December 2004.

On August 19, 2004, the CPUC also approved a project to install approximately 28 miles of 230 kV transmission line from Redwood City to Brisbane, known as the Jefferson-Martin 230 kV Line. The improvement is intended to provide additional transmission system reliability in San Francisco and northern San Mateo County. Construction of this project is expected to be completed in early 2006.

Natural Gas Utility Operations

The Utility owns and operates an integrated natural gas transportation, storage and distribution system in California that extends throughout all or a part of 38 of California's 58 counties and includes most of northern and central California. In 2004, the Utility served approximately 4.1 million natural gas distribution customers. The total volume of natural gas throughput during 2004 was approximately 888 Bcf.

At December 31, 2004, the Utility's natural gas system consisted of 40,123 miles of distribution pipelines, 6,136 miles of transportation pipelines and three storage facilities. The Utility's distribution network connects to the Utility's transportation and storage system at approximately 2,200 major interconnection points. The Utility's Line 400/401 interconnects with the natural gas transportation pipeline of Transcanada's Gas Transmission Northwest Corporation at the California-Oregon border. This line has a receipt capacity at the border of approximately 2.0 Bcf per day. The Utility's Line 300, which interconnects with the U.S. southwest and California-Oregon pipeline systems owned by third parties (Transwestern Pipeline Co., El Paso Natural Gas Company, Questar Southern Trails Pipeline Company and Kern River Pipeline Company), has a receipt capacity at the California-Arizona border of approximately 1.1 Bcf per day. Through interconnections with other interstate pipelines, the Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada and the southwestern United States. The Utility also is supplied by natural gas fields in California.

The Utility also owns and operates three underground natural gas storage fields located along the Utility's transportation and storage system in close proximity to approximately 90% of the Utility's end-user demand. These storage fields have a combined annual cycle capacity of approximately 42 Bcf. In addition, two independent storage operators are interconnected to the Utility's northern California transportation system.

Since 1991, the CPUC has divided the Utility's natural gas customers into two categories: core and noncore customers. This classification is based largely on a customer's annual natural gas usage. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The noncore customer class is comprised of industrial and larger commercial natural gas customers. In 2004, core customers represented more than 99% of the Utility's total customers and 32% of its total natural gas deliveries, while noncore customers comprised less than 1% of the Utility's total customers and 68% of its total natural gas deliveries.

The Utility provides natural gas delivery services to all core and noncore customers connected to the Utility's system in its service territory. Core customers can purchase natural gas from alternate energy service providers or can elect to have the Utility provide both delivery service and natural gas supply. When the Utility provides both supply and delivery, the Utility refers to the service as natural gas bundled service. Currently, over 99% of core customers, representing over 97% of core market demand, receive natural gas bundled services from the Utility.

In accordance with a 1998 ratemaking settlement agreement called the Gas Accord, the Utility stopped providing procurement service to noncore customers in March 2001. During the winter of 2000-2001 when there was a steep increase in natural gas prices, many noncore customers switched to core service in order to receive procurement service from the Utility. In December 2003, the CPUC approved the Utility's request to prohibit electricity generation, cogeneration, enhanced oil recovery and refinery, and other large noncore customers from electing to transfer to core service, and requiring smaller noncore customers to sign up for a minimum five-year term if they elect to transfer to core service. The Utility made this request because of its concern that large increases in the Utility's natural gas supply portfolio demand from significant transfers of noncore customers to core service would raise prices for all other core procurement customers and obligate the Utility to reinforce its pipeline system to provide core service reliability on a short-term basis to serve this new load.

The Utility offers transportation, distribution and storage services as separate and distinct services to its noncore customers. These customers may elect to receive storage services from the Utility or other third party storage providers. Noncore customers interconnected at a transportation level only pay for transportation service, while those interconnected at a distribution level pay for both transportation and distribution service. Noncore customers formerly were able to subscribe for natural gas bundled service as if they were core customers but are no longer allowed to do so. Access to the Utility's gas transportation system is available for all natural gas marketers and shippers, as well as noncore customers.

Customers pay a distribution rate that reflects the Utility's costs to serve each customer class. The Utility has regulatory balancing accounts for core customers designed to ensure that the Utility's results of operations over the long term are not affected by their consumption levels. The Utility's results of operations can, however, be affected by noncore consumption levels because there are no similar regulatory balancing accounts related to noncore customers. Approximately 96% of the Utility's natural gas distribution base revenues are recovered from core customers and 4% are recovered from noncore customers.

The California Gas Report, which presents the outlook for natural gas requirements and supplies for California over a long-term planning horizon, is prepared annually by the California electric and natural gas utilities. The 2004 California Gas Report updated the Utility's annual natural gas requirements forecast for the years 2004 through 2025, forecasting average annual growth in the Utility's natural gas deliveries of approximately 1.2%. The natural gas requirements forecast is subject to many uncertainties and there are many factors that can influence the demand for natural gas, including weather conditions, level of economic activity, conservation, and the number and location of electricity generation facilities.

2004 Natural Gas Deliveries

The following table shows the percentage of the Utility's total 2004 natural gas deliveries represented by each of the Utility's major customer classes:

Total 2004 Natural Gas Deliveries: 888 Bcf

Residential Customers	23%
Transport only Customers (noncore)	68%
Commercial Customers	9%

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2000 through 2004 (excluding subsidiaries) for natural gas, including the classification of sales and revenues by type of service:

	2004	2003	2002	2001	2000
Customers (average for the year):					
Residential	3,812,914	3,744,011	3,738,524	3,705,141	3,642,266
Commercial	215,547	208,857	206,953	205,681	203,355
Industrial	2,178	1,988	1,819	1,764	1,719
Other gas utilities	6	6	5	6	6
Total	4,030,645	3,954,862	3,947,301	3,912,592	3,847,346
Gas supply (MMcf):					
Purchased from suppliers in:					
Canada	205,180	196,278	210,716	209,630	216,684
California	(9,108)	(7,421)	19,533	20,352	32,167
Other states	103,801	102,941	67,878	76,589	75,834
Total purchased	299,873	291,798	298,127	306,571	324,685
Net (to storage) from storage	(532)	1,359	(218)	(27,027)	19,420
Total	299,341	293,157	297,909	279,544	344,105
Utility use, losses, etc.(1)	(19,287)	(14,307)	(16,393)	(8,988)	(62,960)
Net gas for sales	280,054	278,850	281,516	270,556	281,145
Bundled gas sales (MMcf):					
Residential	201,601	198,580	202,141	197,184	210,515
Commercial	78,080	79,891	78,812	72,528	66,443
Industrial	373	379	563	831	4,146
Other gas utilities	—	—	—	13	41
Total	280,054	278,850	281,516	270,556	281,145
Transportation only (MMcf):	597,706	525,353	508,090	646,079	606,152
Revenues (in millions):					
Bundled gas sales:					
Residential	\$ 1,944	\$ 1,836	\$ 1,379	\$ 2,308	\$ 1,681
Commercial	712	697	499	783	513
Industrial	—	1	3	16	35
Other gas utilities	—	1	1	—	—
Miscellaneous	(29)	(31)	127	(93)	84
Regulatory balancing accounts	316	68	11	(253)	132
Bundled gas revenues	2,943	2,572	2,020	2,761	2,445
Transportation service only revenue	270	284	316	375	338
Operating revenues	\$ 3,213	\$ 2,856	\$ 2,336	\$ 3,136	\$ 2,783
Selected Statistics:					
Average annual residential usage (Mcf)	53	53	54	53	59
Average billed bundled gas sales revenues per Mcf:					
Residential	\$ 9.64	\$ 9.25	\$ 6.82	\$ 11.70	\$ 7.98
Commercial	9.12	8.73	6.33	10.80	7.72
Industrial	(0.56)	2.48	4.35	19.15	8.53
Average billed transportation only revenue per Mcf	0.45	0.54	0.62	0.58	0.56
Net plant investment per customer	\$ 1,266	\$ 1,261	\$ 1,006	\$ 970	\$ 1,003

(1) Includes fuel for the Utility's fossil fuel-fired generation plants.



Natural Gas Supplies

The Utility purchases natural gas to serve the Utility's core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have fluctuated, generally based on market conditions. During 2004, the Utility purchased approximately 300,000 MMcf of natural gas (net of the sale of excess supply) from 51 suppliers. Substantially all this natural gas was purchased under contracts with a term of less than one year. The Utility's largest individual supplier represented approximately 10.3% of the total natural gas volume the Utility purchased during 2004.

The following table shows the total volume and the average price of natural gas in dollars per Mcf of the Utility's natural gas purchases by region during each of the last five years. The average prices for Canadian and U.S. southwest gas shown below include the commodity natural gas prices, pipeline demand or reservation charges, transportation charges and other pipeline assessments. The volumes purchased are shown net of sales of excess supplies of gas. In 2004 and 2003, the sale of excess supplies to parties located in California exceeded purchases from parties located in California.

	2004		2003		2002		2001		2000	
	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price
Canada	205,180	\$ 5.37	196,278	\$ 4.73	210,716	\$ 2.42	209,630	\$ 4.43	216,684	\$ 4.05
California(1)	(9,108)	\$ 4.89	(7,421)	\$ 3.39	19,533	\$ 2.88	20,352	\$ 11.55	32,167	\$ 8.20
Other states (substantially all U.S southwest)	103,801	\$ 5.44	102,941	\$ 4.63	67,878	\$ 3.04	76,589	\$ 10.41	75,834	\$ 5.99
Total/weighted average	299,873	\$ 5.41	291,798	\$ 4.73	298,127	\$ 2.59	306,571	\$ 6.40	324,685	\$ 4.92

(1) California purchases include supplies from various California producers and supplies transported into California by others.

Gas Gathering Facilities

The Utility's gas gathering system collects and processes natural gas from third-party wells in California. During 2004, approximately 4% of the gas transported on the Utility's system came from various California producers, with the balance coming from supplies transported into California by others. The natural gas is processed to remove various impurities from the natural gas stream and to odorize the natural gas so that it may be detected in the event of a leak. The facilities include 440 miles of gas gathering pipelines, as well as dehydration, separation, regulation, odorization and metering equipment located at 63 stations. The gas gathering system is geographically dispersed and is located in 14 California counties. Approximately 103 MMcf per day of natural gas flows through the Utility's gas gathering system.

Interstate and Canadian Natural Gas Transportation Services Agreements

In 2004, approximately 68% of the gas transported on the Utility's system came from western Canada. The Utility has a number of arrangements with interstate and Canadian third-party transportation service providers to serve core customers' service demands. The Utility has firm transportation agreements for delivery of natural gas from western Canada to the United States- Canadian border with TransCanada NOVA Gas Transmission, Ltd. and TransCanada PipeLines Ltd., B.C. System. These companies' pipeline systems connect at the border to the pipeline system owned by Gas Transmission Northwest Corporation which provides natural gas transportation services to interconnection points with the Utility's natural gas transportation system in the area of California near Malin, Oregon. The Utility has a firm transportation agreement with Gas Transmission Northwest Corporation for these services.

During 2004, approximately 28% of the gas transported on the Utility's system came from the western United States, excluding California. The Utility has firm transportation agreements with

Transwestern Pipeline Co., or Transwestern, and El Paso Natural Gas Company, or El Paso, to transport this natural gas from supply points in this region to interconnection points with the Utility's natural gas transportation system in the area of California near Topock, Arizona.

The following table shows certain information about the Utility's firm natural gas transportation agreements, including the contract quantities, contract durations and associated demand charges, net of sales of excess supplies, for capacity reservations. These agreements require the Utility to pay fixed demand charges for reserving firm capacity on the pipelines. The total demand charges may change periodically as a result of changes in regulated tariff rates approved by Canadian regulators in the case of TransCanada NOVA Gas Transmission, Ltd. and TransCanada PipeLines Ltd., B.C. System, and the FERC in all other cases. The Utility recovers these demand charges through the CPIM. The Utility may, upon prior notice and with the CPUC approval, extend each of these natural gas transportation agreements. On the FERC-regulated pipelines, the Utility has either a right of first refusal or evergreen rights allowing it to renew natural gas transportation agreements at the end of their terms. If another prospective shipper also wants the capacity, the Utility would be required to match the competing bid with respect to both price and term.

Pipeline	Expiration Date	Quantity MDth per day	Demand Charges for the Year Ended December 31, 2004
			(In millions)
El Paso Natural Gas Company	12/31/2004	64	4.1
TransCanada NOVA Gas Transmission, Ltd.	12/31/2006	593	26.8
TransCanada PipeLines Ltd., B.C. System	10/31/2006	584	10.3
Gas Transmission Northwest Corporation	10/31/2006	610	55.1
Transwestern Pipeline Co.	03/31/2007	150	17.7
El Paso Natural Gas Company	03/31/2007	40	3.8
El Paso Natural Gas Company	04/30/2005	100	8.2
El Paso Natural Gas Company	03/31/2006	64	—

Competition

Historically, energy utilities operated as regulated monopolies within service territories where they were essentially the sole suppliers of natural gas and electricity services. These utilities owned and operated all of the businesses and facilities necessary to generate, transport and distribute energy. Services were priced on a combined, or bundled, basis with rates charged by the energy companies designed to include all the costs of providing these services. Under traditional cost-of-service regulation, the utilities undertake a continuing obligation to serve their customers, in return for which the utilities were authorized to charge regulated rates sufficient to recover their costs of service, including timely recovery of their operating expenses and a reasonable return on their invested capital. The objective of this regulatory policy was to provide universal access to safe and reliable utility services. Regulation was designed in part to take the place of competition and ensure that these services were provided at fair prices. In recent years, energy utilities have faced intensifying pressures to unbundle, or price separately, those services that are no longer considered natural monopolies. The most significant of these services are the commodity components—the supply of electricity and natural gas.

The driving forces behind these competitive pressures have been customers who believe they can obtain energy at lower unit prices and competitors who want access to those customers. Regulators and legislators responded to these forces by providing for more competition in the energy industry. Regulators and legislators, to varying degrees, have required utilities to unbundle rates in order to allow customers to compare unit prices of the utilities and other providers when selecting their energy service provider.

The FERC's policies have supported the development of a competitive electricity generation industry. FERC Order 888, issued in 1996, established standard terms and conditions for parties seeking access to regulated utilities' transmission grids. The FERC's subsequent Order 2000, issued in late 1999, established national standards for regional transmission organizations and advanced the view that a regulated, unbundled transmission sector should facilitate competition in both wholesale electricity generation and retail electricity markets. The FERC's standard market design proposal issued in July 2002 encourages unbundled transmission. The ISO also issued its own comprehensive market design proposal to effect changes to the structure and operation of the California electricity market, subject to the FERC's approval. The FERC has approved the first phase of the ISO's new rules and implementation of the first phase was substantially completed in the fourth quarter of 2004. A later phase to establish integrated forward markets and locational marginal pricing and revise congestion management would be implemented in the future, assuming FERC approval. The ISO is expected to file proposed tariff language with the FERC later in 2005 to address these issues, with implementation of a new market design in 2007. Both the timing and substance of the FERC's regional transmission organization policy and the FERC's and the ISO's market design processes may be affected by any energy legislation Congress may pass.

In July 2003, in order to limit opportunities for transmission providers to favor their own generation, facilitate market entry for generation competitors by streamlining and standardizing interconnection procedures, and encourage needed investment in generator and transmission infrastructure, the FERC issued final rules on the interconnection of generators larger than 20 MW with a transmission system. The rules will require regulated transmission providers, such as the Utility or the ISO, generally to use standard interconnection procedures and a standard agreement for generator interconnections. These rules would require the Utility and the ISO to revise the current form of agreements and procedures used when constructing facilities to interconnect new generators. Numerous parties have requested rehearing and a stay of the generator interconnection rules. The FERC has ordered that the rules will not become effective until after the FERC accepts new tariff changes to implement the rules. The Utility, along with other transmission owners and the ISO, initially, filed proposed tariffs changes on January 20, 2004. In July 2004, the FERC summarily rejected those filings, based on a finding that the ISO did not satisfy the FERC's standards for an "Independent Entity" within the meaning of the FERC's rules. The FERC directed the ISO and the transmission owners to make a new filing with stronger justification for any California-specific deviations from the FERC's generally applicable rules. In January 2005, the Utility, along with other transmission owners and the ISO, re-filed with the FERC the proposed tariff changes and procedures, as required by the FERC. It is uncertain when the FERC will act on the proposed tariff changes.

In 1998, California implemented AB 1890, which mandated the restructuring of the California electricity industry and established a market framework for electricity generation in which generators and other electricity providers were permitted to charge market-based prices for wholesale electricity. AB 1890 also gave customers the choice of continuing to buy electricity from the California investor-owned electric utilities or, beginning in April 1998, entering into contracts to purchase electricity from alternate energy service providers (*i.e.* , becoming direct access customers). The CPUC suspended the right of retail end-user customers to become direct access customers on September 20, 2001. The CPUC has assessed an additional charge on certain direct access customers to avoid a shift of costs from direct access customers to customers who receive bundled service.

In October 2003, the CPUC instituted a rulemaking implementing AB 117, which permits California cities and counties to purchase and sell electricity for their residents once they have registered as community choice aggregators. Under AB 117, the Utility would continue to provide distribution, metering and billing services to the community choice aggregators' customers and be those customers' provider of electricity of last resort. However, once registration has occurred, each

community choice aggregator would procure electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. To prevent a shifting of costs to customers of a utility who receive bundled services, AB 117 requires the CPUC to determine a cost-recovery mechanism so that retail end-users of the community choice aggregator will pay an appropriate share of the DWR's and the Utility's costs. AB 117 also authorized the Utility to recover from each community choice aggregator any costs of implementing the program that are reasonably attributable to the community choice aggregator, and to recover from customers any costs of implementing the program not reasonably attributable to a community choice aggregator.

The Utility faces competition in the electricity distribution business as a result of the construction of duplicate distribution facilities to serve specific existing or new customers, condemnation of the Utility's distribution facilities by local governments or districts, and technological developments. These and other forms of competition may result in stranded investment capital, loss of customer growth and additional barriers to cost recovery. In addition, self-generation by the Utility's customers may result in stranded investment capital, loss of customer growth and additional barriers to cost recovery. As customers and local public officials explore their energy options in light of the recent California energy crisis, these bypass risks are increasing and may increase further if the Utility's rates exceed the cost of other available alternatives.

A number of local governments and districts in California are considering various forms of providing electric distribution services within the Utility's service territory. The City and County of San Francisco (along with other California communities) have been considering municipalization of the Utility's electricity distribution system within their jurisdictions. In addition, the Sacramento Municipal Utility District currently is considering annexing portions of the Utility's service territory, with the objective of enabling the district to replace the Utility within these areas. Some existing public power entities, such as the Modesto and Merced Irrigation Districts, also are expanding their services in the Utility's service area. Finally, some districts that are not currently distributing electricity, including the El Dorado Irrigation District and the South San Joaquin Irrigation District, are considering building facilities that would duplicate the Utility's facilities. In May 2003, the South San Joaquin Irrigation District revealed its plans to invest over \$40 million to duplicate the Utility's distribution facilities and begin serving existing and new customers in and around Manteca. In 2002, the City of Hercules formed its own municipal utility for the purpose of competing with the Utility to serve new customers within the city. In 2003, the City of Hercules began providing electricity service to a 200-home subdivision and a large commercial customer, and has been actively pursuing additional residential and commercial customers. The Utility cannot currently predict the impact of these actions on the Utility's business, although one possible outcome is a decline in the demand for the electricity that the Utility provides, which would result in a decline in the Utility's revenues.

The Natural Gas Industry

FERC Order 636, issued in 1992, required interstate natural gas pipeline companies to divide their services into separate gas commodity sales, transportation and storage services. Under Order 636, interstate natural gas pipeline companies must provide transportation service regardless of whether the customer (often a local gas distribution company) buys the natural gas commodity from these companies.

In 1998, the Utility implemented the Gas Accord under which the natural gas transportation and storage services the Utility provides were separated for ratemaking purposes from the Utility's distribution services. The Gas Accord changed the terms of service and rate structure for natural gas transportation, allowing the Utility's core customers greater flexibility to purchase natural gas from competing suppliers. The Utility's noncore customers purchase their natural gas from producers, marketers and brokers, and purchase their preferred mix of transportation, storage and distribution services from the Utility. Although they can select the gas suppliers of their choice, substantially all

core customers buy natural gas, as well as transportation and distribution services, from the Utility as bundled service. The Gas Accord market structure has been extended by the CPUC through 2007.

The Utility competes with other natural gas pipeline companies for customers transporting natural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas and the quality and reliability of transportation services. The most important competitive factor affecting the Utility's market share for transportation of natural gas to the southern California market is the total delivered cost of western Canadian natural gas relative to the total delivered cost of natural gas from the southwestern United States. The total delivered cost of natural gas includes, in addition to the commodity cost, transportation costs on all pipelines that are used to deliver the natural gas, which, in the Utility's case, includes the cost of transportation of the natural gas from Canada to the California border and the amount that the Utility charges for transportation from the border to southern California. In general, when the total cost of western Canadian natural gas increases relative to other competing natural gas sources, the Utility's market share of transportation services into southern California decreases. In addition, Kern River Pipeline Company completed a major expansion of its pipeline system in May 2003 that increased its capacity to deliver natural gas into the southern California market by approximately 900 MMcf per day. As a result this expansion, the volume of natural gas that the Utility delivers to the southern California market may decrease, although to date the Utility has not experienced any significant decrease in its volumes shipped. The Utility also competes for storage services with other third-party storage providers, primarily in northern California.

From time to time, existing pipeline companies propose to expand their pipeline systems for delivery of natural gas into northern and central California. As a result of the California energy crisis, several new natural gas pipeline proposals were initiated to serve proposed new generation facilities for northern and central California. Many of the electricity generation projects have been cancelled or delayed, making it difficult for sponsors of the various gas pipeline projects to acquire enough firm capacity commitments to go forward with construction.

PG&E Corporation's Regulatory Environment

Federal Energy Regulation

PG&E Corporation and its subsidiaries are exempt from all provisions, except Section 9(a)(2), of the Public Utility Holding Company Act of 1935, or PUHCA. Currently, PG&E Corporation has no expectation of becoming a registered holding company under PUHCA. In 2001, the California Attorney General filed a petition with the SEC requesting the SEC to review and revoke PG&E Corporation's exemption from PUHCA and to begin fully regulating the activities of PG&E Corporation and its affiliates. PG&E Corporation responded in detail to the California Attorney General petition demonstrating that PG&E Corporation qualified for an exemption from PUHCA and that there was no basis for action by the SEC. To date, the SEC has neither instituted an investigation nor ordered hearings regarding the matters raised in the California Attorney General's petition.

During 2003 and 2004, proposed federal energy legislation was considered by the U.S. Congress. If it had been adopted, the legislation would, among other things, have repealed PUHCA. PUHCA currently imposes significant regulatory barriers to mergers and acquisitions involving public utilities and public utility holding companies. The repeal of PUHCA could trigger a period of consolidation among public utilities, as well as acquisitions of public utilities by other businesses. As a result, the repeal of PUHCA could increase competitive pressures on the energy utility industry, including competition from sources the Utility does not currently view as competitors. The proposed effective date for the repeal of PUHCA, as well as the proposed effective date for proposed legislation that would replace PUHCA, was 12 months after the passage of the legislation. Under the proposed legislation that would replace PUHCA, public utilities and public utility holding companies would

remain under the regulatory oversight of the FERC, but not the SEC. Similar legislation is likely to be considered in 2005.

State Energy Regulation

PG&E Corporation is not a public utility under the laws of California and is not subject to regulation as such by the CPUC. However, the CPUC approval authorizing the Utility to form a holding company was granted subject to various conditions set forth in CPUC decisions issued in 1996 and 1999 related to finance, human resources, records and bookkeeping, and the transfer of customer information. The financial conditions provide that:

- the Utility is precluded from guaranteeing any obligations of PG&E Corporation without prior written consent from the CPUC;
- the Utility's dividend policy must continue to be established by the Utility's Board of Directors as though the Utility were a stand-alone utility company;
- the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner, must be given first priority by PG&E Corporation's Board of Directors, (known as the first priority condition); and
- the Utility must maintain on average its CPUC-authorized utility capital structure, although it shall have an opportunity to request a waiver of this condition if an adverse financial event reduces the Utility's equity ratio by 1% or more.

The CPUC also has adopted complex and detailed rules governing transactions between California's electricity and natural gas distribution companies and their non-regulated affiliates. The rules permit non-regulated affiliates of regulated utilities to compete in the affiliated utility's service territory, and also to use the name and logo of their affiliated utility, provided that in California the affiliate includes certain designated disclaimer language which emphasizes the separateness of the entities and that the affiliate is not regulated by the CPUC. The rules also address the separation of regulated utilities and their non-regulated affiliates and information exchange among the affiliates. The rules prohibit each utility from engaging in certain practices that would discriminate against energy service providers that compete with that utility's non-regulated affiliates. In January 2004, the CPUC adopted rules that prohibit regulated utility electric procurement from entering into power procurement related transactions with an affiliate, subject to the following exceptions:

- anonymous transactions through approved interstate brokers and exchanges, provided that the solicitation/bidding process is structured so that the identity of the seller is not known to the buyer until agreement is reached, and vice-versa;
- transactions for natural gas services between the regulated utility and affiliates or operating divisions that are found necessary and beneficial for ratepayer interests, subject to the receipt and review of a management audit; and
- transactions that occur pursuant to contracts with affiliates that were already existing on January 22, 2004.

In December 2004, the CPUC lifted its ban on affiliate transactions for long-term electricity procurement through all source competitive solicitations but retained the ban on short-term electricity procurement transactions.

The CPUC also has established specific penalties and enforcement procedures for affiliate rules violations. Utilities are required to self-report affiliate rules violations.

On April 3, 2001, the CPUC issued an order instituting an investigation into whether the California investor-owned electric utilities, including the Utility, have complied with past CPUC decisions, rules and orders authorizing their holding company formations and/or governing affiliate transactions, as well as applicable statutes. The order states that the CPUC will, among other matters, investigate the utilities' transfer of money to their holding companies, including during times when their utility subsidiaries were experiencing financial difficulties; the failure of the holding companies to financially assist the utilities when needed; the transfer by the holding companies of assets to unregulated subsidiaries; and the holding companies' actions to "ringfence" their unregulated subsidiaries. Under the Settlement Agreement the CPUC has agreed to dismiss with prejudice PG&E Corporation and the Utility from the CPUC's investigation as to past practices.

On January 9, 2002, the CPUC issued two decisions in its pending investigation. In one decision, the CPUC, for the first time, adopted a broad interpretation of the first priority condition and concluded that the condition, at least under certain circumstances, includes the requirement that each of the holding companies "infuse the utility with all types of capital necessary for the utility to fulfill its obligation to serve." Nevertheless, the CPUC dismissed PG&E Corporation (but no other utility holding company) from the investigation. In the second decision, the CPUC asserted that it maintains jurisdiction to enforce the conditions against PG&E Corporation and similar holding companies and to modify, clarify or add to the conditions.

In November 2003, PG&E Corporation and the holding companies of the other major California investor-owned electric utilities filed petitions for review of the CPUC's decisions with the California Court of Appeal. On May 21, 2004, the California Court of Appeal issued an opinion finding that the CPUC has limited jurisdiction over the holding companies to enforce the conditions imposed by the CPUC when the CPUC authorized the formation of the holding companies, but that the CPUC's decision interpreting the first priority condition was not ripe for review. PG&E Corporation appealed the decision of the California Court of Appeal finding that the CPUC had limited jurisdiction to the California Supreme Court. On September 1, 2004, the California Supreme Court denied the petition. On February 11, 2005, a CPUC administrative law judge issued a ruling noting that the pending CPUC investigation had been dormant for some time and requesting comments on whether the investigation should remain open. The ruling also stated that if no comments were received, a draft decision would be prepared for CPUC consideration closing the proceeding.

PG&E Corporation and the Utility believe that they have complied with applicable statutes, CPUC decisions, rules and orders.

On January 10, 2002, the California Attorney General filed a complaint in the San Francisco Superior Court against PG&E Corporation and its directors, as well as against the directors of the Utility, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions Code Section 17200. Among other allegations, the California Attorney General alleges that PG&E Corporation violated the various conditions established by the CPUC in decisions approving the holding company formation. A similar complaint filed by the City and County of San Francisco also is pending. These complaints are not affected by the Settlement Agreement. For more information, see "Item 3—Legal Proceedings" below.

The Utility's Regulatory Environment

Various aspects of the Utility's business are subject to a complex set of energy, environmental and other governmental laws, regulations and regulatory proceedings at the federal, state and local levels. This section and the "Ratemaking Mechanisms" section below summarize some of the more significant laws, regulations and regulatory mechanisms affecting the Utility. These sections are not an exhaustive description of all the laws, regulations and regulatory proceedings that affect the Utility. The energy laws, regulations and regulatory proceedings may change or be implemented or applied in a way that

the Utility does not currently anticipate. For discussion of specific regulatory proceedings affecting the Utility, see the MD&A.

Federal Energy Regulation

The FERC

The FERC is an independent agency within the U.S. Department of Energy, or DOE, that regulates the transmission of electricity in interstate commerce and the sale for resale of electricity in interstate commerce. The FERC regulates electricity transmission, interconnections, tariffs and conditions of service of the ISO and the terms and rates of wholesale electricity sales. The ISO is responsible for providing open access transmission service on a non-discriminatory basis, meeting applicable reliability criteria, planning transmission system additions and assuring the maintenance of adequate reserves of generation capacity. In addition, the FERC has jurisdiction over the Utility's electricity transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities and the interstate sale and transportation of natural gas.

In response to the California energy crisis, the FERC issued a series of orders in the spring and summer of 2001 and July 2002 aimed at prospectively mitigating extreme wholesale energy prices like those that prevailed in 2000 and 2001. These orders established a cap on bids for real-time electricity and ancillary services of \$250 per MWh (unless a generator could demonstrate that its costs justified a rate in excess of \$250 per MWh) and established various automatic mitigation procedures. As of December 2003, all sellers with market-based rate authority became subject to, and incorporated in their market-based rate tariffs, behavioral conditions designed to prevent market manipulation.

In 2005, the FERC is expected to consider ISO market monitoring and oversight in connection with the FERC's review of the ISO's market design proposals. Market monitoring and mitigation also may be affected by any energy legislation Congress may pass.

Various entities, including the Utility and the state of California are seeking up to \$8.9 billion in refunds for electricity overcharges on behalf of California electricity purchasers from May 2000 to June 2001 through a proceeding pending at the FERC. This FERC proceeding, the "Refund Proceeding," commenced on August 2, 2000 when a complaint was filed against all suppliers in the ISO and PX markets. On July 25, 2001, the FERC held that refunds would be available for certain overcharges, and established a process to determine the amount of the overcharges that will be refunded. The FERC asserted that it would not order market-wide refunds for periods before October 2, 2000, because under a federal statute it can only order refunds beginning 60 days after a complaint for overcharges was filed and the first complaint for overcharges was not filed with the FERC until August 2, 2000. In December 2002, a FERC ALJ issued an initial decision in the Refund Proceeding finding that power suppliers overcharged the utilities, the state of California and other buyers approximately \$1.8 billion from October 2, 2000 to June 20, 2001, but that California buyers still owe the power suppliers approximately \$3.0 billion, leaving approximately \$1.2 billion in net unpaid bills.

In March 2003, the FERC confirmed most of the ALJ's findings in the Refund Proceeding, but partially modified the refund methodology to include use of a new natural gas price methodology as the basis for mitigated prices. The FERC indicated that it would consider later allowances claimed by sellers for natural gas costs above the natural gas prices in the refund methodology. In addition, the FERC directed the ISO and the PX (which operates solely to reconcile remaining refund amounts owed) to make compliance filings establishing refund amounts by March 2004. The ISO calculation process has been continuing, and the ISO has indicated that it plans to make its compliance filing by the first half of 2005. The PX cannot make its compliance filing until after the ISO has made its filing. In October 2003, the FERC affirmed its March 2003 decision. Various parties have filed appeals with the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit, of the various FERC orders in the

Refund Proceeding. Although the Ninth Circuit originally held those appeals in abeyance while the FERC process continued, on October 22, 2004, the Ninth Circuit ordered that the appeals should proceed. According to a schedule developed by the Ninth Circuit, the parties are required to submit all briefs by March 2005 to address the issues of which power suppliers are subject to refunds, the appropriate time period for which refunds can be ordered, and which transactions are subject to refunds. These matters will be considered at oral argument before the Ninth Circuit on April 12 and 13, 2005, and a decision is expected in the following months.

The final refunds will not be determined until the FERC issues a final decision in the Refund Proceeding, following the ISO and PX compliance filings and the resolution of the appeals of the FERC's orders. The FERC is uncertain when it will issue a final decision in the Refund Proceeding, after which further appellate review is expected. In addition, future refunds could increase or decrease as a result of retroactive adjustments proposed by the ISO, which incorporate revised data provided by the Utility and other entities.

As noted above, the FERC asserted in the Refund Proceeding that it does not have the power to direct the power suppliers to make comprehensive market-wide refunds to customers for the period before October 2, 2000. However, in the FERC's separate proceedings to investigate whether tariff violations occurred in the period before October 2, 2000, the FERC has asserted that it has the power to order power suppliers to disgorge any profits if the FERC finds that the tariffs in force at that time were violated or subject to manipulation. In addition, in September 2004, acting in a separate case from the Refund Proceeding and the FERC's investigative proceedings, the Ninth Circuit found that the FERC has the authority to provide refunds for tariff violations involving inadequate transaction reporting for sales into the California spot markets throughout the period before October 2, 2000. The Ninth Circuit remanded the case to the FERC to determine the appropriate remedy. Pending a decision on the suppliers' request for a rehearing of this Ninth Circuit decision, the FERC has not yet acted on the September 2004 remand order. It is uncertain whether the Ninth Circuit's decision interpreting the FERC's power to order refunds will be upheld and how it will be applied by the FERC.

The Utility recorded approximately \$1.8 billion of claims filed by various electricity generators in its Chapter 11 proceeding as liabilities subject to compromise. This amount is subject to a pre-petition offset of approximately \$200 million, reducing the net liability recorded to approximately \$1.6 billion. Under a bankruptcy court order, the aggregate allowable amount of ISO, PX and generator claims was limited to approximately \$1.6 billion. The Utility currently estimates that the claims would have been reduced to approximately \$1.0 billion based on the refund methodology recommended in the FERC ALJ's initial decision. The recalculation of market prices according to the revised methodology adopted by the FERC in its March 2003 decision could further reduce the amount of the suppliers' claims by several hundred million dollars. This reduction could be offset by the amount of any additional fuel cost allowance for suppliers if they demonstrate that natural gas prices were higher than the natural gas prices assumed in the refund methodology. The FERC has directed that sellers claiming a fuel cost allowance should submit their claims to an independent auditor before inclusion of any amounts in an ISO calculation of refunds and offsets for such fuel costs.

The Utility has entered into various settlements with power suppliers resolving the Utility's claims against these power suppliers. Although settlement discussions with a number of other major sellers and other market participants are continuing, the Utility cannot predict whether these settlement negotiations will be successful. The net after-tax amounts received by the Utility under settlements reduced the amount of the Settlement Regulatory Asset. Customers also will receive the benefit of any future energy supplier refunds received by the Utility. See discussion entitled "Contingencies" in MD&A.

On November 25, 2003, the FERC issued Order No. 2004, its final rule on standards of conduct for interstate natural gas pipelines and public utilities (jointly referred to as transmission providers). The standards of conduct are designed to ensure that transmission providers do not provide affiliated market participants with preferential access to service or information. In Order No. 2004, the FERC consolidated the previously separate standards of conduct for interstate natural gas pipelines and electric transmission providers and expanded the range of affiliates covered by the standards. In accordance with Order No. 2004, on September 22, 2004, the Utility posted its plan for compliance with the standards of conduct on its internet website, www.pge.com.

The NRC

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's Diablo Canyon power plant and Humboldt Bay Unit 3. NRC regulations require extensive monitoring and review of the safety, radiological, environmental and security aspects of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. Safety requirements promulgated by the NRC have, in the past, necessitated substantial capital expenditures at the Utility's Diablo Canyon power plant and additional significant capital expenditures could be required in the future.

State Energy Regulation

The CPUC

The CPUC has jurisdiction to set the rates, terms and conditions of service for the Utility's electricity distribution, natural gas distribution and natural gas transportation and storage services in California. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electricity and natural gas retail customers, rate of return, rates of depreciation, aspects of the siting and operation of natural gas transportation assets, oversight of nuclear decommissioning and aspects of the siting of the electricity transmission system. Ratemaking for retail sales from the Utility's generation facilities is under the jurisdiction of the CPUC. To the extent this electricity is sold for resale into wholesale markets, however, it is under the ratemaking jurisdiction of the FERC. In addition, the CPUC conducts various reviews of utility performance and conducts investigations into various matters, such as deregulation, competition and the environment, in order to determine its future policies. The CPUC consists of five members appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms.

California Legislature

Over the last several years, the Utility's operations have been significantly affected by statutes passed by the California legislature, including:

- *Assembly Bill 1890.* AB 1890 mandated the restructuring of the California electricity industry, commencing in 1998 with the implementation of a market framework for electricity generation in which generators and other energy providers were permitted to charge market-based rates for wholesale electricity and the Utility's customers were given the choice of becoming direct access customers;
- *Assembly Bill 6X.* AB 6X, enacted in January 2001 in response to the California energy crisis, prohibited disposition of utility-owned generation facilities before January 1, 2006;
- *Assembly Bill 1X.* AB 1X authorized the DWR, beginning on February 1, 2001, to purchase electricity and sell that electricity directly to the investor-owned electric utilities' retail customers.

AB 1X required the California investor-owned electric utilities, including the Utility, to deliver that electricity and act as the DWR's billing and collection agent;

- *Senate Bill 1976.* SB 1976, enacted in September 2002, required the CPUC to allocate electricity from contracts that the DWR entered into under AB 1X among the customers of the California investor-owned electric utilities, required the utilities to file short- and long-term procurement plans with the CPUC, contemplated that the utilities would resume buying electricity pursuant to these plans by January 1, 2003, and mandated new electricity procurement balancing accounts to allow timely recovery by the utilities of differences between recorded revenues and costs incurred under approved procurement plans;
- *Senate Bill 1078.* SB 1078, enacted in September 2002, creates a renewable portfolio standard for investor-owned utilities that requires annual 1% increases of renewable electrical procurement purchases until renewable resources equal 20% of total retail sales in 2017; and
- *Senate Bill 772.* SB 772, enacted in June 2004, (1) authorized the CPUC to approve the issuance of energy recovery bonds, or ERBs, to refinance the \$2.21 billion regulatory asset established under the Settlement Agreement, or Settlement Regulatory Asset, (2) established a dedicated rate component to securitize the ERBs, and (3) authorized the CPUC to impose a charge for the dedicated rate component on the Utility's electricity distribution customers, subject to certain limited exceptions. On February 10, 2005, PG&E Energy Recovery Funding LLC, or PERF, a limited liability company which is wholly owned and consolidated by the Utility (but legally separate from the Utility), issued \$1.9 billion of ERBs that are secured by this dedicated rate component. The proceeds of the issuance of ERBs were paid by PERF to the Utility and will be used by the Utility to refinance the remaining unamortized after-tax balance of the Settlement Regulatory Asset.

The California Energy Resources Conservation and Development Commission

The California Energy Resources Conservation and Development Commission, commonly called the California Energy Commission, or CEC, is the state's primary energy policy and planning agency. The CEC is responsible for licensing of all thermal power plants over 50 MW, overseeing funding programs that support public interest energy research; advance energy science and technology through research, development and demonstration; and provide market support to existing, new and emerging renewable technologies. In addition, the CEC is responsible for forecasting future energy needs that will be used by the CPUC in determining the adequacy of the utilities' electricity procurement plans.

Other Regulation

The Utility obtains a number of permits, authorizations and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines and gas compressor station facilities. Discharge permits, various Air Pollution Control District permits, U.S. Department of Agriculture-Forest Service permits, FERC hydroelectric generation facility and transmission line licenses, and NRC licenses are some of the more significant examples. Some licenses and permits may be revoked or modified by the granting agency if facts develop or events occur that differ significantly from the facts and projections assumed in granting the approval. Furthermore, discharge permits and other approvals and licenses are granted for a term less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. The Utility currently has seven hydroelectric projects and one transmission line project undergoing FERC relicensing. The Utility will begin relicensing proceedings on two additional hydroelectric projects within the next two years.

The Utility has over 520 franchise agreements with various cities and counties that permit the Utility to install, operate and maintain the Utility's electric, natural gas, oil and water facilities in the public streets and roads. In exchange for the right to use public streets and roads, the Utility pays annual fees to the cities and counties under the franchises. Franchise fees are computed pursuant to statute under either the Broughton Act or the Franchise Act of 1937. However, there are 38 charter cities that can set a fee of their own determination. The Utility also periodically obtains permits, authorizations and licenses in connection with distribution of electricity and natural gas. Under these permits, authorizations and licenses the Utility has rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain related operations.

Ratemaking Mechanisms

Overview

Cost of Service Ratemaking

In January 2004, the CPUC determined that the retail electric rate freeze implemented as part of electric industry restructuring in 1998 ended on January 18, 2001. In February 2004, the CPUC approved a rate design settlement to implement an annual electricity rate reduction of approximately \$799 million to begin on January 1, 2004. As a result of the Settlement Agreement and these CPUC decisions, the Utility's rates are now determined based on its costs of service. Electric rates reflect the sum of individual revenue requirement components, including base revenue requirements set by general rate cases as described below, revenue requirements for the regulatory assets provided under the Settlement Agreement, electricity procurement costs, and the DWR's requirement, among others. Changes in any individual revenue requirement will change customers' electricity rates and the Utility's revenues.

Revenue Requirements

Before the rates for the Utility's electricity and natural gas utility services can be set, revenue requirements must first be determined. The components of revenue requirements for electricity and natural gas utility service include depreciation, operating, administrative and general expenses, taxes and return on investment, as applicable, for each area of these services, including distribution, transmission, transportation, generation, procurement and public purpose programs. Revenue requirements are designed to allow a utility an opportunity to recover its reasonable costs of providing utility services, including a return of, and a fair rate of return on, its investment in utility facilities, or rate base. Revenue requirements are then allocated among customer classes and specific rates designed to produce the required revenue are established. In the Utility's rate cases, intervenors have the opportunity to comment on the Utility's application. The issues raised by these comments are then resolved by the appropriate regulatory agency. If the Utility and the intervenors can settle these issues, these settlements are submitted to the regulatory agency for approval.

General Rate Cases

The Utility's primary revenue requirement proceeding is the general rate case, or GRC, filed with the CPUC. In the GRC, the CPUC authorizes the Utility to collect from customers an amount known as base revenues to recover base business and operational costs related to the Utility's electricity and natural gas distribution and electricity generation operations. The GRC typically sets annual revenue requirement levels for a three-year rate period. The CPUC authorizes these revenue requirements in GRC proceedings based on a forecast of costs for the first, or test, year. After authorizing the revenue requirements, the CPUC allocates revenue requirements among customer classes (mainly residential, commercial, industrial and agricultural) and establishes specific rate levels. Typical intervenors in the Utility's GRC include the ORA and TURN. The next GRC will cover the period of 2007-2009.

Attrition Rate Adjustments

The CPUC may authorize the Utility to receive annual increases for the years between GRCs in the base revenues authorized for the test year of a GRC to avoid a reduction in earnings in those years due to, among other things, inflation and increases in invested capital. These adjustments are known as attrition rate adjustments. Attrition rate adjustments provide increases in the revenue requirements that the Utility is authorized to collect in rates for electricity and natural gas distribution and electricity generation operations.

Cost of Capital Proceedings

The CPUC generally conducts an annual cost of capital proceeding to determine the Utility's authorized capital structure and the authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation assets. The cost of capital proceeding establishes the percentage components that common equity, preferred equity and debt will represent in the Utility's total authorized capital structure for a specific year. The CPUC then establishes the authorized return on common equity, preferred equity and debt that the Utility will have the opportunity to collect in its authorized rates. For 2005, this proceeding also set the authorized rate of return for the Utility's gas transportation and storage assets.

Baseline Allowance

The CPUC sets and periodically revises a baseline allowance for the Utility's residential gas and electricity customers. A customer's baseline allowance is the amount of its monthly usage that is covered under the lowest possible natural gas or electric rate. Electricity baseline usage is also exempt from certain surcharges. Natural gas or electricity usage in excess of the baseline allowance is covered by higher rates that increases with usage.

DWR Electricity and DWR Revenue Requirements

As a consequence of the California energy crisis, on January 17, 2001, the Governor of California signed an order declaring an emergency and authorizing the DWR to purchase electricity to maintain the continuity of supply to retail customers. This was followed by AB 1X, which authorized the DWR to purchase electricity and sell that electricity directly to the California investor-owned utilities' retail end-user customers and to issue revenue bonds to finance electricity purchases. AB 1X also required the Utility to deliver the electricity purchased by the DWR over the Utility's distribution systems and to act as a billing and collection agent for the DWR, without taking title to DWR purchased electricity or reselling it to the Utility's customers.

AB 1X allows the DWR to recover its costs of electricity and associated transmission and related services, principal and interest on bonds issued to finance the purchase of electricity, administrative costs and certain other amounts associated with purchasing electricity through a revenue requirement. AB 1X also authorizes the CPUC to set rates to cover the DWR's revenue requirements, but prohibits the CPUC from increasing electricity rates for residential customers who use less electricity than 130% of their existing baseline quantities.

Under AB 1X, the DWR was prohibited after December 31, 2002 from entering into new electricity purchase contracts and from purchasing electricity on the spot market. SB 1976, which became law in September 2002, required the CPUC to allocate electricity from existing DWR contracts among the customers of the California investor-owned electric utilities, including the Utility's customers. On September 19, 2002, the CPUC issued a decision allocating electricity from the DWR contracts to the customers of the three California investor-owned electric utilities. The DWR continues to be legally and financially responsible for these contracts. The electricity provided under 19 of the DWR contracts was allocated to the Utility's customers. The Utility is responsible for scheduling and dispatching the electricity subject to the DWR allocated contracts on a least-cost basis and for many administrative functions associated with these contracts.

The DWR pays for its costs of purchasing electricity from a revenue requirement collected from electricity customers of the three California investor-owned electric utilities through what is known as a power charge. The Utility's customers also must pay what is known as a bond charge to pay a share of the DWR's revenue requirements to recover costs associated with the DWR's \$11.3 billion bond offering completed in November 2002. The proceeds of this bond offering were used to repay the State of California and lenders to the DWR for electricity purchases made before the implementation of the DWR's revenue requirement and to provide the DWR with funds to make its electricity purchases. Because the Utility acts as a billing and collection agent for the DWR, amounts collected for the DWR and any adjustments are not included in the Utility's revenues.

Procurement Resumption and Procurement Plans

On January 1, 2003, the California investor-owned electric utilities resumed responsibility for procuring electricity to meet their residual net open positions (*i.e.* , that portion of the Utility's electricity customers' demand not satisfied by electricity that the Utility generates or has under contract, or by electricity provided under the DWR allocated contracts). They also became responsible for scheduling and dispatching the electricity subject to the DWR allocated contracts on a least-cost basis and for many administrative functions associated with those contracts. The utilities also were required by SB 1976 to submit short-term and long-term procurement plans to the CPUC for approval.

Effective January 1, 2003, under California law, the Utility established a balancing account, the Energy Resource Recovery Account, or ERRRA, designed to track and allow recovery of the difference between the recorded electricity procurement revenues and actual costs incurred under the Utility's authorized procurement plans, excluding the costs associated with the DWR allocated contracts and certain other items. SB 1976 requires the CPUC to review the revenues and costs associated with a utility's electricity procurement plan at least semi-annually and adjust retail electricity rates or order refunds, as appropriate when the aggregate over-collections or under-collections exceed 5% of the utility's prior year electricity procurement revenues, excluding amounts collected for the DWR.

All load-serving entities, including the utilities, energy service providers and future community choice aggregators, must achieve an electricity planning reserve margin of 15% to 17% in excess of peak capacity electricity requirements by June 1, 2006. Also, beginning in 2006, the utilities and other load-serving entities are required to secure 90% of their electricity needs during the peak energy months of May through September through forward contracts at least one year in advance.

On December 16, 2004, the CPUC issued a final decision which approved, with certain modifications, each California investor-owned electric utility's long-term electricity procurement plan, or LTPP, in order to authorize each utility to plan for and procure the resources necessary to provide reliable service to their customers for the ten-year period 2005-2014. The decision recognizes that each utility will have capacity needs over the ten-year period, especially in 2011 when most of the DWR contracts expire. The decision states that a major issue in the proceeding is the extent to which the utilities will be compensated for investments or purchases that they must make in order to meet their obligation to provide reliable service to their customers, noting that the implementation of community choice aggregation, departing municipal load, and the potential for allowing new direct access all create a great degree of uncertainty as to the amount of load the existing utilities will be responsible for serving in the future. The decision includes the following key points:

- The decision finds that the Utility's strategy of adding 1,200 MW of capacity and new peaking generation in 2008 and an additional 1,000 MW of new peaking and dispatchable generation in 2010 through requests for offers, or RFOs, is reasonable and compatible with the Utility's resource needs under its medium load preferred case scenario, does not crowd out policy-preferred resources, and is a reasonable level of commitment given load uncertainty.

- To meet the utilities' resource requirements, the utilities are required to solicit bids from providers of all potential sources of new generation (e.g. conventional or renewable resources to be provided under turnkey developments, buyouts, or power purchase agreements, or PPAs) through a single, open, transparent and competitive RFO process, although an utility can tailor a RFO to meet specific resource needs. In particular, bids for long-term generation resources (whether PPAs or utility-owned) would be evaluated side-by-side. In evaluating bids, the IOUs are required to:
 - procure the maximum amount of renewable generation resources, and be prepared to defend any selection of fossil-fuel generation resources over renewable resources,
 - employ the Least-Cost Best-Fit methodology when evaluating bids for PPAs and utility-owned generation resources, taking into account the qualitative and quantitative attributes (such as performance risk, credit risk, price diversity, term, and operational flexibility) associated with each bid, and
 - employ a "greenhouse gas adder" to evaluate fossil-fuel generation bids as a method to recognize the cost of greenhouse gas emissions to develop a more accurate price comparison between fossil-fuel, renewable and demand-side bids (the greenhouse gas adder would be used for analytical purposes only and would not be paid to a generator).
- The CPUC has agreed that it will consider the debt equivalence impact of procurement contracts on credit ratings in future cost of capital proceedings. The Utility is required to employ Standard & Poor's method for assessing the debt equivalence of power purchase agreements when evaluating bids in an all-source solicitation, except that the debt equivalence factor should be 20% instead of 30%.
- The utilities are prohibited from recovering initial capital costs in excess of their final bid price for utility-owned generation resources. If final project costs are less than the final bid price, the savings would be shared with customers and any cost overruns would be absorbed by the utilities. Costs of future plant additions and annual operating and maintenance costs and similar costs incurred by an utility would be eligible for cost-of service ratemaking treatment.
- Affiliates of the utilities are permitted to participate in the bidding process for long-term generation resources, subject to certain guidelines and safeguards, including a requirement that the utility use an independent third party evaluator in resource solicitations where there are bids that involve affiliates or utility-built or utility-turnkey development projects. The independent evaluator will not be able to make binding decisions on behalf of the utility.
- The utilities are permitted to recover their net stranded costs of all new fossil-fuel generation resources from all customers, including departing customers, for a period of 10 years or the life of the PPA, whichever is less, provided that the CPUC will allow the utilities an opportunity to justify a longer recovery period on a case-by-case basis. Stranded costs arising from renewable generation procurement activities can be collected from all customers, including departing load, over the life of the contract. The utilities are required to take appropriate steps to minimize potential stranded costs by selling excess energy and capacity needs into the marketplace and crediting the revenues from these sales against the utilities' costs.
- The mandatory rate adjustment mechanism under SB 1976, which otherwise would cease on January 1, 2006, has been extended to the length of a resource commitment or 10 years, whichever is longer.
- With respect to the utilities' contracting authority, the decision permits the utilities to enter into short-term, mid-term and long-term contracts with starting delivery dates through 2014, provided the utilities submit necessary compliance filings and provided that contracts with terms five years

or longer are submitted to the CPUC for pre-approval. The decision adopts a rolling 10-year procurement period, noting that the LTPPs cover a 10-year period and will be updated and reviewed every 2 years. The decision grants the Utility's petition for modification of its existing short-term procurement plan to permit all utilities to conduct procurement using negotiated bilateral agreements for transactions up to 3 calendar months, or one quarter, forward. The decision notes that ultimately the CPUC will eliminate short-term procurement plans and the utilities will act in accordance with a single CPUC-approved plan; but until then, the utilities' existing short-term plans remain in effect and any updates or modifications should be filed with an advice letter within 30 days after the issuance of the decision. The Utility filed an update to its short-term plan on January 18, 2005. The decision requires the utilities to submit a compliance filing updating their procurement plans to reflect the changes and modifications in the decision by March 25, 2005.

- The decision directs the utilities to meet CPUC-mandated energy efficiency goals over the 10-year period, but defers consideration of the \$245 million incremental revenue requirement requested by the Utility to fund energy efficiency programs for 2006 through 2008 to the CPUC's energy efficiency rulemaking proceeding.

Electricity Transmission

The Utility's electricity transmission revenues and its wholesale and retail transmission rates are subject to authorization by the FERC. The Utility has two sources of transmission revenues: charges under the Utility's transmission owner tariff and charges under specific contracts with existing wholesale transmission customers that pre-date the Utility's participation in the ISO. Customers that receive transmission services under these pre-existing contracts, referred to as existing transmission contract customers, are charged individualized rates based on the terms of their contracts. Transmission rates established by the FERC in the Utility's transmission owner rate cases are included by the CPUC in the Utility's retail electricity rates and collected from retail electricity customers receiving bundled service under the federal filed rate doctrine.

Transmission Owner Rate Cases

Under the FERC's regulatory regime, the Utility is able to file a new base transmission rate case under the Utility's transmission owner tariff whenever the Utility deems it necessary to increase its rates within certain guidelines set forth by the FERC. The Utility is typically able to charge new rates, subject to refund, before the outcome of the FERC ratemaking review process.

The Utility's transmission owner tariff includes two rate components:

- Base transmission rates, which are intended to recover the Utility's operating and maintenance expenses, depreciation and amortization expenses, interest expense, tax expense and return on equity; and
- Rates to recover ISO charges for both reliability service costs and an ISO charge associated with a ten-year shift from utility-specific transmission charges to an ISO grid-wide charge, both of which are discussed below.

The Utility derives the majority of the Utility's transmission revenue from base transmission rates.

Transmission Control Agreement

The Utility has entered into a Transmission Control Agreement, or TCA, with the ISO and other participating transmission owners (including Southern California Edison, or SCE, San Diego Gas & Electric Company, and several California municipal utilities) under which the transmission owners have

assigned operational control of their electricity transmission systems to the ISO. The Utility is required to give two years notice and receive regulatory approval if it wishes to withdraw from the TCA.

Reliability Must Run Agreements

The ISO also has entered into reliability must run, or RMR, agreements with various power plant owners, including the Utility, that require designated units in certain power plants, known as RMR units, to remain available to generate electricity upon the ISO's demand when needed for local transmission system reliability. As a participating transmission owner under the TCA, the Utility is responsible for the ISO's costs paid under RMR agreements to power plant owners within or adjacent to the Utility's service territory.

At December 31, 2004, the Utility estimated that it could be obligated to pay the ISO approximately \$570 million in costs incurred under these RMR agreements during the period January 1, 2005 to December 31, 2006. Of this amount, the Utility estimates that it would receive approximately \$42 million under its RMR agreements during the same period. These costs and revenues are subject to applicable ratemaking mechanisms. For a discussion of a proposed settlement agreement entered into in January 2005 with Mirant Corporation and various of its subsidiaries to resolve the Utility's claims that it was overcharged under Mirant's RMR agreements and other RMR-related issues that could affect the Utility, see the section titled "Reliability Must Run Agreements" in MD&A.

Reliability Services Costs

The ISO bills the Utility for reliability services based on payments that the ISO makes to generators under reliability must run agreements and to others to support reliability of the Utility's transmission system. The costs of reliability must run agreements attributed to supporting the Utility's historic transmission control area are charged to the Utility as a participating transmission owner. These costs were approximately \$425 million in 2004. Under the Utility's transmission owner tariff, the Utility charges its customers rates designed to recover these reliability service charges, without mark-up or service fees. The Utility tracks costs and revenues related to reliability services in the reliability services balancing account. Periodically, the Utility's electricity transmission rates are adjusted to refund over-collections to the Utility's customers or to collect any under-collections from customers.

Transmission Access Charge

In March 2000, the ISO filed an application with the FERC seeking to establish its own transmission access charge as directed by AB 1890. The ISO's transmission access charge methodology provides for transition to a uniform statewide high-voltage transmission rate, based on the revenue requirements of all participating transmission owners associated with facilities operated at 200 kV and above. The transmission access charge methodology also requires the Utility and other transmission owners, during a ten-year transition period, to pay a charge intended to reimburse other transmission owners (who are generally new ISO participants) whose costs are higher than that embedded in the uniform rate. Under the ISO's application, the Utility's obligation for this cost differential would be capped at \$32 million per year during the ten-year transition period. In December 2004, the FERC issued an Order in this proceeding accepting the ISO's transmission access charge methodology.

Natural Gas

The Gas Accord

In 1998, the Utility implemented a ratemaking pact called the Gas Accord, under which the Utility's natural gas transportation and storage services were separated for ratemaking purposes from its distribution services. The Gas Accord established natural gas transportation rates and natural gas

storage rates. On December 16, 2004, the CPUC approved a multi-party settlement agreement to retain the Gas Accord market structure, and resolve the rates, and terms and conditions of service for the Utility's natural gas transportation and storage system for the three-year period of 2005-2007. The Utility continues to be at risk of not recovering its natural gas transportation and storage costs and does not have regulatory balancing account protection for over-collections or under-collections of most of its natural gas transportation or storage revenues, except for core local transmission revenue.

Biennial Cost Allocation Proceeding

The Utility's natural gas distribution costs and balancing account balances are allocated to customers in the Biennial Cost Allocation Proceeding. This proceeding normally occurs every two years and is updated in the interim year for purposes of adjusting natural gas rates to recover from customers any under-collection, or refund to customers any overcollection, in the balancing accounts. Balancing accounts for gas distribution and other authorized expenses accumulate differences between authorized amounts and actual revenues.

Natural Gas Procurement

The Utility sets the natural gas procurement rate for core customers monthly based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rates.

Under the core procurement incentive mechanism, or the CPIM, the Utility's natural gas purchase costs (including Canadian and interstate capacity and volumetric transportation charges) are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is currently between 99% and 102% of the benchmark, are considered reasonable and fully recoverable, in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive three-fourths of the savings when the costs are below 99% of the benchmark. Any awards associated with the CPIM are reflected annually in the purchased natural gas balancing account after the close of the annual period ending October 31 that is used to measure the CPIM. These awards are not included in earnings until approved by the CPUC.

On September 2, 2004, the CPUC issued an order establishing a process, whereby utilities receive CPUC pre-approval of contracts for interstate and Canadian pipeline capacity to support their natural gas procurement activities.

Gas Public Purpose Program Surcharges

Authorized amounts for gas public purpose programs have been recovered through gas rate surcharges since January 1, 2001, pursuant to AB 1002, and are set on an annual basis. Effective March 1, 2005, the Utility intends to change its treatment of these gas surcharges to remove them from revenues and treat the surcharges as taxes, in accordance with a recent CPUC decision.

Interstate and Canadian Natural Gas Transportation and Storage

The Utility's interstate and Canadian natural gas transportation agreements with third party service providers are governed by tariffs that detail rates, rules and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. United States tariffs are approved for each pipeline for service to all of its shippers, including the Utility, by the FERC in a FERC ratemaking review process and the applicable Canadian tariffs by the Alberta Energy and

Utilities Board and the National Energy Board. The Utility's agreements with interstate and Canadian natural gas transportation service providers are administered as part of the Utility's core natural gas procurement business. Their purpose is to transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada and the southwestern United States) to the points at which the Utility's natural gas transportation system begins.

Environmental Matters

The following discussion includes certain forward-looking information relating to estimated expenditures for environmental protection measures and the possible future impact of environmental compliance. The information below reflects current estimates that are periodically evaluated and revised. Future estimates and actual results may differ materially from those indicated below. These estimates are subject to a number of assumptions and uncertainties, including changing laws and regulations, the ultimate outcome of complex factual investigations, evolving technologies, selection of compliance alternatives, the nature and extent of required remediation, the extent of the facility owner's responsibility and the availability of recoveries or contributions from third parties.

General

The Utility is subject to a number of federal, state and local laws and requirements relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of activities, including:

- The discharge of pollutants into air, water and soil;
- The identification, generation, storage, handling, transportation, treatment, disposal, record keeping, labeling, reporting of, remediation of and emergency response in connection with, hazardous, and radioactive substances; and
- Land use, including endangered species and habitat protection.

The penalties for violation of these laws and requirements can be severe, and may include significant fines, damages and criminal or civil sanctions. These laws and requirements also may require the Utility, under certain circumstances, to interrupt or curtail operations. To comply with these laws and requirements, the Utility may need to spend substantial amounts from time to time to construct, acquire, modify or replace equipment, acquire permits and/or marketable allowances or other emission credits for facility operations and clean up or decommission waste disposal areas at the Utility's current or former facilities and at third-party sites where the Utility may have disposed of wastes.

Generally, the Utility has recovered the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean up of sites that contain hazardous substances are subject to a special ratemaking mechanism.

In 1994, the CPUC established a ratemaking mechanism under which the Utility is authorized to recover hazardous waste remediation costs for environmental claims (*e.g.* , for cleaning up the Utility's facilities and sites where the Utility has sent hazardous substances) from customers. That mechanism allows the Utility to include 90% of the hazardous waste remediation costs in the Utility's rates without review. Hazardous waste remediation costs in the future are likely to be significant. However, based on the Utility's past experience, it believes that it can recover most of these costs in rates and through insurance claims.

Ten percent of any net insurance recoveries associated with hazardous waste remediation sites are assigned to the Utility's customers. The balance of any insurance recoveries, (90%) are retained by the Utility until it has been reimbursed for the 10% share of clean-up costs not included in rates. There also is a special sharing of the costs incurred pursuing recovery under insurance contracts. In

connection with electricity industry restructuring, this mechanism may no longer be used to recover electricity generation-related clean-up costs for contamination caused by events occurring after January 1, 1998. The Utility cannot provide assurance, however, that these costs will not be material, or that the Utility will be able to recover its costs in the future.

Air Quality

The Utility's generation plants and natural gas pipeline operations are subject to numerous air pollution control laws, including the federal Clean Air Act and similar state and local statutes. These laws and regulations cover, among other pollutants, those contributing to the formation of ground-level ozone, carbon monoxide, sulfur dioxide, nitrogen oxide and particulate matter. Fossil fuel-fired electric utility plants and gas compressor stations used in the Utility's pipeline operations are sources of air pollutants and, therefore, are subject to substantial regulation and enforcement oversight by the applicable governmental agencies.

During 2003 and 2004, various multi-pollutant initiatives were introduced in the U.S. Senate and House of Representatives. These initiatives include limits on the emissions of nitrogen oxide, sulfur dioxide, mercury and carbon dioxide, and some would allow the use of trading mechanisms to achieve or maintain compliance with the proposed rules. Hearings on legislation to amend the federal Clean Air Act have been held in the U.S. Senate but not in the House of Representatives. Similar legislation is expected to be introduced in 2005.

As a result of the Utility's divestiture of most of its fossil fuel-fired and geothermal generation facilities, the Utility's nitrogen oxide emission reduction compliance costs have been reduced significantly. Two of the local air districts in which the Utility owns and operates fossil fuel-fired generation facilities have adopted final rules under the California Clean Air Act and the federal Clean Air Act that required reductions in nitrogen oxide emissions from the facilities of approximately 90% by 2004. The Utility is in compliance with these rules. The Utility is permitted to recover in customer rates the Utility's costs for its nitrogen oxide retrofit projects related to natural gas compressor stations on the Utility's Line 300, which delivers gas from the southwest. Several air districts are considering nitrogen oxide rules that would apply to the Utility's other natural gas compressor stations in California. Eventually, the rules are likely to require nitrogen oxide reductions of up to 80% at many of these natural gas compressor stations. Substantially all these costs will be capital costs which the Utility expects to recover through rates.

In addition, current federal and state regulatory initiatives could increase the Utility's compliance costs and capital expenditures primarily with respect to the Utility's gas transportation facilities, fleet and fuel storage tanks, to comply with laws relating to emissions of carbon dioxide and other greenhouse gases, particulates and other toxic pollutants. If enacted, these laws could require the Utility to replace equipment, install additional pollution controls, purchase various emission allowances, or curtail operations. Although associated costs and capital expenditures could be material, the Utility expects that it would be able to recover these costs and capital expenditures in rates.

Water Quality

The federal Clean Water Act generally prohibits the discharge of any pollutants, including heat, into any body of surface water, except in compliance with a discharge permit issued by a state environmental regulatory agency and/or the U.S. Environmental Protection Agency, or the EPA. The Utility's generation facilities are subject to federal and state water quality standards with respect to discharge constituents and thermal effluents. The Utility's steam-electric generation facilities comply in all material respects with the discharge constituents standards and the thermal standards. In addition, under the federal Clean Water Act, the Utility is required to demonstrate that the location, design, construction and capacity of generation facility cooling water intake structures reflect the best

technology available for minimizing adverse environmental impacts at its existing water-cooled thermal plants. The Utility has submitted detailed studies of each steam-electric generation facility's intake structure to various governmental agencies and each power plant's existing intake structure was found to meet the best technology available requirements.

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a National Pollutant Discharge Elimination System, or NPDES, permit issued by the Central Coast Regional Water Quality Control Board, or Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at an average temperature of no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, recreation, commercial/sport fishing, marine and wildlife habitat, shellfish harvesting and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement of this matter pursuant to which the Central Coast Board has agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology meets the best technology available requirements. As part of the Central Coast settlement agreement, the Utility has agreed to take measures to preserve certain acreage north of the plant and will fund approximately \$6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the Central Coast settlement agreement. On June 17, 2003, the Central Coast settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of this settlement agreement is that the Central Coast Board renew Diablo Canyon's NPDES permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the Central Coast settlement agreement accepted in March 2003, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately \$30 million. The Utility would seek to recover these costs through rates charged to customers.

In addition, on July 9, 2004, the EPA published regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations affect existing electricity generation facilities using over 50 million gallons per day, typically including some form of "once-through" cooling. The Utility's Diablo Canyon, Hunters Point and Humboldt Bay power plants are among an estimated 539 generation facilities nationwide that are affected by this rulemaking. The regulations establish a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. Significant capital investment may be required to achieve the standards. The regulations allow site-specific compliance determinations if a facility's cost of compliance is significantly greater than either the benefits achieved or the compliance costs considered by the EPA. The Utility is developing compliance strategies for each plant.

The Utility has a comprehensive program to monitor a network of groundwater wells near the Utility's Topock natural gas compressor station located near Needles, California. In mid-January 2004 and again in mid-February 2005, hexavalent chromium was detected in samples taken from groundwater

monitoring wells located approximately 65 feet from the Colorado River. The Utility is cooperating with the California Department of Toxic Substances Control, or DTSC, other state agencies, appropriate federal agencies, and other interested parties, to develop a plan to ensure that the hexavalent chromium does not impact the Colorado River. In 2004, the Utility took interim measures to control the chromium plume via extracting impacted groundwater and spent approximately \$23.6 million. The Utility plans to continue these activities and work toward the development of a final plan to address the plume in 2005. The Utility currently estimates that it will spend at least \$25 million in 2005 with respect to this matter. The Utility is currently in the process of obtaining additional samples from these and other wells and testing these additional samples. Although work at this site poses several technical and regulatory obstacles, the Utility does not expect the outcome of this matter to have a material adverse effect on its results of operations or financial condition.

Endangered Species

Many of the Utility's facilities and operations are located in or pass through areas that are designated as critical habitats for federal or state-listed endangered, threatened or sensitive species. The Utility may be required to incur additional costs or be subjected to additional restrictions on operations if additional threatened or endangered species are listed or additional critical habitats are designated near the Utility's facilities or operations. The Utility is seeking to secure "habitat conservation plans" to ensure long-term compliance with the state and federal endangered species acts. The Utility expects that it will be able to recover costs of complying with state and federal endangered species acts through rates.

Hazardous Waste Compliance and Remediation

The Utility's facilities are subject to the requirements issued by the EPA under the Resource Conservation and Recovery Act, or RCRA, and the Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended, or CERCLA, as well as other state hazardous waste laws and other environmental requirements. CERCLA and similar state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, damages to natural resources and the costs of required health studies. In the ordinary course of the Utility's operations, the Utility generates waste that falls within CERCLA's definition of a hazardous substance and, as a result, has been and may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment.

The Utility assesses, on an ongoing basis, measures that may be necessary to comply with federal, state and local laws and regulations related to hazardous materials and hazardous waste compliance and remediation activities. The Utility has a comprehensive program to comply with hazardous waste storage, handling and disposal requirements issued by the EPA under RCRA and CERCLA, state hazardous waste laws and other environmental requirements.

The Utility has been, and may be, required to pay for environmental remediation at sites where the Utility has been, or may be, a potentially responsible party under CERCLA and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, gas gathering sites, compressor stations and sites where the Utility stores, recycles and disposes of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

Operations at the Utility's current and former generation facilities may have resulted in contaminated soil or groundwater. Although the Utility sold most of its geothermal generation facilities and most of its fossil fuel-fired plants, in many cases the Utility retained pre-closing environmental liability under various environmental laws. The Utility currently is investigating or remediating several such sites with the oversight of various governmental agencies.

In addition, the federal Toxic Substances Control Act regulates the use, disposal and cleanup of polychlorinated biphenyls, or PCBs, which are used in certain electrical equipment. During the 1980s, the Utility initiated two major programs to remove from service all of the distribution capacitors and network transformers containing high concentrations of PCBs. These programs removed the vast majority of PCBs existing in the Utility's electricity distribution system.

The Utility is assessing whether and to what extent remedial action may be necessary to mitigate potential hazards posed by certain disposal sites and retired manufactured gas plant sites. During their operation from the mid-1800s through the early 1900s, manufactured gas plants produced lampblack and tar residues. The lampblack and tar residues are byproducts of a process that the Utility, its predecessor companies, and other utilities used as early as the 1850s to manufacture gas from coal and oil. As natural gas became widely available (beginning about 1930), the Utility's manufactured gas plants were removed from service. The residues that may remain at some sites contain chemical compounds that now are classified as hazardous. The Utility owns all or a portion of 28 manufactured gas plant sites. The Utility has a program, in cooperation with environmental agencies, to evaluate and take appropriate action to mitigate any potential health or environmental hazards at these sites. The Utility spent approximately \$5.8 million in 2004 and expects to spend approximately \$7.2 million in 2005 on these projects. The Utility expects that expenses will increase as remedial actions related to these sites are approved by regulatory agencies. In addition, approximately 68 other manufactured gas plants in the Utility's service territory are now owned by others. The Utility has not incurred any significant costs associated with these non-owned sites, but it is possible that the Utility may incur additional cleanup costs related to these sites in the future if hazardous substances for which the Utility has liability are found.

Under environmental laws such as CERCLA, the Utility has been or may be required to take remedial action at third-party sites used for the disposal of waste from the Utility's facilities, or to pay for associated cleanup costs or natural resource damages. The Utility is currently aware of eight such sites where investigation or cleanup activities are currently underway. At the Geothermal Incorporated site in Lake County, California, the Utility has been directed to perform site studies and any necessary remedial measures by regulatory agencies. At the Casmalia disposal facility near Santa Maria, California, the Utility and several other generators of waste sent to the site have entered into a court-approved agreement with the EPA that requires the Utility and the other parties to perform certain site investigation and mitigation measures.

In addition, the Utility has been named as a defendant in several civil lawsuits in which plaintiffs allege that the Utility is responsible for performing or paying for remedial action at sites that it no longer owns or never owned. Remedial actions may include investigations, health and ecological assessments and removal of wastes.

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can estimate a range of reasonably likely clean-up costs. The Utility reviews its remediation liability on a quarterly basis for each site where it may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites, and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility

records the costs at the lower end of this range. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. The Utility estimates the upper end of the cost range using reasonably possible outcomes least favorable to the Utility.

The Utility had an undiscounted environmental remediation liability of approximately \$327 million at December 31, 2004, and approximately \$314 million at December 31, 2003. During the year ended December 31, 2004, the liability increased by approximately \$13 million mainly due to reassessment of the estimated cost of remediation and remediation payments. The approximately \$327 million accrued at December 31, 2004, includes approximately \$102 million related to the pre-closing remediation liability associated with divested generation facilities and approximately \$225 million related to remediation costs for those generation facilities that the Utility still owns, gas gathering sites, compressor stations, third-party disposal sites, and manufactured gas plant sites that either are owned by the Utility or are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites. Of the approximately \$327 million environmental remediation liability, approximately \$144 million has been included in prior rate setting proceedings and the Utility expects that approximately \$141 million will be allowable for inclusion in future rates. The Utility also recovers its costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers.

The Utility's undiscounted future costs could increase to as much as \$480 million if the other potentially responsible parties are not financially able to contribute to these costs, or if the extent of contamination or necessary remediation is greater than anticipated. The amount of approximately \$480 million does not include an estimate for the cost of remediation at known sites owned or operated in the past by the Utility's predecessor corporations for which the Utility has not been able to determine whether a liability exists.

Nuclear Fuel Disposal

Under the Nuclear Waste Policy Act of 1982, or Nuclear Waste Act, the DOE is responsible for the transportation and ultimate long-term disposal of spent nuclear fuel and high-level radioactive waste. Under the Nuclear Waste Act, utilities are required to provide interim storage facilities until permanent storage facilities are provided by the federal government. The Nuclear Waste Act mandates that one or more permanent disposal sites be in operation by 1998. Consistent with the law, the Utility entered into a contract with the DOE providing for the disposal of the spent nuclear fuel and high-level radioactive waste from the Utility's nuclear power facilities beginning not later than January 1998. The DOE has been unable to meet its contractual commitment to begin accepting spent fuel. First, there was a delay in identifying a storage site. Then, after the DOE selected Yucca Mountain, Nevada for the site, protracted litigation has prevented the DOE from constructing the storage facility. The DOE's current estimate for an available site to begin accepting physical possession of the spent nuclear fuel is 2010. However, considerable uncertainty exists regarding when the DOE will begin to accept spent fuel for storage or disposal. Under the Utility's contract with the DOE, if the DOE completes a storage facility by 2010, the earliest Diablo Canyon's spent fuel would be accepted for storage or disposal would be 2018.

On January 22, 2004, the Utility filed separate complaints in the U.S. Court of Federal Claims against the DOE alleging that the DOE has breached its contractual obligation to move used nuclear fuel from Diablo Canyon and Humboldt Bay Unit 3 to a national repository beginning in 1998. The complaints seek recovery of the Utility's costs incurred for the planning and development of on-site storage at both facilities as a result of the DOE's failure to meet its obligations. The Utility's complaints are similar to complaints filed by at least 20 other utilities with nuclear facilities.

At the projected level of operation for Diablo Canyon, Diablo Canyon power plant's existing spent fuel pools have sufficient capacity to enable it to operate through approximately 2007. The NRC granted authorization to the Utility in March 2004 to build an on-site dry cask storage facility to store spent fuel through approximately 2021 for Unit 1 and to 2024 for Unit 2. Several intervenors appealed the NRC's decision to the U.S. Court of Appeals for the Ninth Circuit. Oral arguments on that appeal are expected in the first quarter of 2005 with a decision anticipated in the second half of 2005. PG&E Corporation and the Utility cannot predict the outcome of these appeals.

In April 2004, San Luis Obispo County (the California county where Diablo Canyon is located) issued a permit under the California Coastal Act, subject to a number of conditions. The Utility, along with several other interested parties, filed appeals of the County's decision with the California Coastal Commission. The Utility's appeal challenged one of the conditions pertaining to the granting of public access to the coast and other portions of the Utility's property surrounding Diablo Canyon. On December 8, 2004, the California Coastal Commission granted the Utility's application for a coastal development permit authorizing it to proceed with its planned construction of an on-site dry cask storage facility. The Commission granted the Utility's appeal, denied the appeals of other parties and conducted a de novo review of the application. The Commission's December 8, 2004 decision requires that the Utility provide expanded public access to the coast and other lands surrounding Diablo Canyon, although such public access is less expansive than the County had originally required and will be subject to a one-year study process. Construction of the on-site dry cask storage facility is expected to start in the second quarter of 2005 after grading permits are obtained from the County of San Luis Obispo.

To provide another storage alternative in the event construction of the dry cask storage facility is delayed, the Utility also has requested that the NRC approve another storage option to install a temporary storage rack in each unit's existing spent fuel storage pool that would increase the on-site storage capability to permit the Utility to operate Unit 1 until 2010 and Unit 2 to 2011. This temporary option would not require local or California Coastal permission permits to be obtained. If the on-site dry cask storage facility is not completed and the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operations of Diablo Canyon may have to be curtailed or halted until such time as additional spent fuel can be safely stored.

In July 1988, the NRC gave the Utility final approval to store radioactive waste from the Utility's retired nuclear generating facility, Humboldt Bay Unit 3, at the plant until 2015 before ultimately decommissioning the unit. The Utility has agreed to remove all spent fuel when the federal disposal site is available. In 1988, the Utility completed the first step in the decommissioning of Humboldt Bay Unit 3 and placed the unit into SAFSTOR, a condition of monitored safe storage in which the unit will be maintained until the spent nuclear fuel is removed from the spent fuel pool and the facility is dismantled. The used fuel assemblies currently are stored in metal racks submerged in a pool of water called a wet storage pool. The specially designed storage pool is constructed of steel-reinforced concrete and lined with stainless steel.

In June 2004, the Utility reported to the NRC that the Utility was unable to account for all of the used fuel segments from Humboldt Bay Unit 3 that the Utility's records indicate were sent to storage and that the Utility was evaluating whether the used fuel was placed in the storage pool. Although the used fuel segments have not been found after an initial search of the pool, the Utility is continuing its efforts to search other, less accessible locations in the pool. It is possible that a complete search may not be concluded until the 390 used fuel assemblies, along with other components, are removed from the pool, as part of the plant decommissioning process currently set for 2009.

The Utility has filed an application with the NRC seeking authorization to build an on-site dry cask storage facility at Humboldt Bay Unit 3. The Utility plans to file an application with the California Coastal Commission for a permit to build the facility. Transfer of spent fuel to a dry cask facility would

allow early decommissioning of Humboldt Bay Unit 3. The Utility anticipates that, if it were licensed to employ an on-site dry cask storage facility, the Utility would receive a 20-year initial license for on-site dry cask storage with the opportunity to receive a 20-year renewal term.

Nuclear Decommissioning

Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear power facilities consist of two units at the Diablo Canyon power plant and the retired facility at Humboldt Bay Unit 3. For ratemaking purposes, the eventual decommissioning of Diablo Canyon Unit 1 is scheduled to begin in 2021 and to be completed in 2040. Decommissioning of Diablo Canyon Unit 2 is scheduled to begin in 2025 and to be completed in 2041, and decommissioning of Humboldt Bay Unit 3 is scheduled to begin in 2009 and be completed in 2015.

The estimated nuclear decommissioning cost for the Diablo Canyon power plant and Humboldt Bay Unit 3 is approximately \$1.83 billion in 2004 dollars (or approximately \$5.25 billion in future dollars). These estimates are based on a 2002 decommissioning cost study and are prepared in accordance with CPUC requirements and are used in the Utility's Nuclear Decommissioning Costs Triennial Proceeding discussed below. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear plants. Actual decommissioning costs are expected to vary from this estimate because of changes in assumed dates of decommissioning, regulatory requirements, technology, costs of labor, materials and equipment.

The estimated nuclear decommissioning cost described above is used for regulatory purposes. Under generally accepted accounting principles, or GAAP, the decommissioning cost estimate is calculated using a different method. In accordance with Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations," the Utility adjusts its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. In addition, the Utility records the Utility's total nuclear decommissioning obligation as an asset retirement obligation on the Utility's Consolidated Balance Sheet. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately \$1.2 billion at December 31, 2004 and \$1.1 billion at December 31, 2003.

The CPUC has established the Nuclear Decommissioning Costs Triennial Proceeding to determine the Utility's estimated decommissioning costs and to establish the associated annual revenue requirement and escalation factors for consecutive three-year periods. The Utility's revenue requirements for nuclear decommissioning costs are recovered from customers through a nonbypassable charge that will continue until those costs are fully recovered.

Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. The Utility has three decommissioning trusts for its Diablo Canyon and Humboldt Bay Unit 3 nuclear facilities. The Utility has elected that two of these trusts be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, the Utility is allowed a deduction for the payments made to the qualified trusts. These payments cannot exceed the amount collected from customers through the decommissioning charge. The qualified trusts are subject to a lower tax rate on income and capital gains, thereby increasing the trusts' after-tax returns. Among other requirements, to maintain the qualified trust status, the Internal Revenue Service, or IRS, must approve the amount to be contributed to the qualified trusts for any taxable year. The remaining non-qualified trust is exclusively for decommissioning Humboldt Bay Unit 3. The Utility cannot deduct amounts contributed to the non-qualified trust until the decommissioning costs are actually incurred.

In 2004, the Utility collected approximately \$18.4 million in rates and contributed approximately \$18.4 million, on an after-tax basis, to the nuclear decommissioning trusts. For 2005, the Utility is

authorized to collect approximately \$18.4 million in rates for decommissioning Humboldt Bay Unit 3. Of this amount, the Utility expects to contribute approximately \$18.4 million, on an after-tax basis, to the qualified trusts for Humboldt Bay Unit 3. The Utility has requested the IRS approve the new amounts to be contributed to the qualified trusts for Humboldt Bay Unit 3. If the IRS does not approve the request, the Utility must withdraw any contributions it made to the qualified trusts for 2003 and 2004 and contribute the withdrawn amounts, on an after-tax basis, to the non-qualified trust. The Utility would likely request that the CPUC approve an increase in revenue requirements to make up for the reduced amount contributed to the non-qualified trust due to the reduced rate of return attributable to taxes.

The funds in the decommissioning trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the Utility's nuclear facilities. The trusts maintain substantially all of their investments in debt and equity securities. All earnings on the assets held in the trusts, net of authorized disbursements from the trusts and investment management and administrative fees, are reinvested. Amounts may not be released from the decommissioning trusts until authorized by the CPUC. At December 31, 2004, the Utility had accumulated decommissioning trust funds with an estimated fair value of approximately \$1.6 billion, based on quoted market prices and net of deferred taxes on unrealized gains.

For more information about nuclear decommissioning, see Note 9 of the Notes to the Consolidated Financial Statements in the Annual Report.

Electric and Magnetic Fields

Electric magnetic fields, or EMFs, naturally result from the generation, transmission, distribution and use of electricity. In January 1991, the CPUC opened an investigation to address increasing public concern, especially with respect to schools, regarding potential health risks that may be associated with EMFs from utility facilities. In its order instituting the investigation, the CPUC acknowledged that the scientific community has not reached consensus on the nature of any health impacts from contact with EMFs, but went on to state that a body of evidence has been compiled that raises the question of whether adverse health impacts might exist.

In November 1993, the CPUC adopted an interim EMF policy for California energy utilities that, among other things, requires California energy utilities to take no-cost and low-cost steps to reduce EMFs from new or upgraded utility facilities. California energy utilities were required to fund an EMF education program and an EMF research program managed by the California Department of Health Services. As part of the Utility's effort to educate the public about EMFs, the Utility provides interested customers with information regarding the EMF exposure issue. The Utility also provides a free field measurement service to inform customers about EMF levels at different locations in and around their residences or commercial buildings.

In October 2002, the California Department of Health Services released its report, based primarily on its review of studies by others, evaluating the possible risks from EMFs, to the CPUC and the public. The report's conclusions contrast with other recent reports by authoritative health agencies in that the California Department of Health Services' report has assigned a higher probability to the possibility that there is a causal connection between EMF exposures and a number of diseases and conditions, including childhood leukemia, adult leukemia, amyotrophic lateral sclerosis and miscarriages.

It is not yet clear what actions the CPUC will take to respond to this report. In August 2004, the CPUC opened a rulemaking proceeding to determine if there are improvements that should be made to the CPUC's existing rules and regulations concerning EMFs. Possible outcomes include, but are not limited to, continuation of current policies and imposition of more stringent measures to mitigate EMF exposures. The Utility cannot estimate the costs of such mitigation measures with any certainty at this

time. However, such costs could be significant, depending on the particular mitigation measures undertaken, especially if the Utility must ultimately relocate existing power lines.

The Utility currently is not involved in third-party litigation concerning EMFs. In August 1996, the California Supreme Court held that homeowners are barred from suing utilities for alleged property value losses caused by fear of EMFs from power lines. The court expressly limited its holding to property value issues, leaving open the question as to whether lawsuits for alleged personal injury resulting from exposure to EMFs are similarly barred. The Utility was one of the defendants in civil litigation in which plaintiffs alleged personal injuries resulting from exposure to EMFs. In January 1998, the appeals court in this matter held that the CPUC has exclusive jurisdiction over personal injury and wrongful death claims arising from allegations of harmful exposure to EMFs and barred plaintiffs' personal injury claims. Plaintiffs filed an appeal of this decision with the California Supreme Court. The California Supreme Court declined to hear the case.

Item 2. *Properties.*

The Utility's corporate headquarters consist of approximately 1.8 million square feet of office space located in several buildings in San Francisco, California. In addition to this corporate office space, the Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, all of which are described above under "Electricity Utility Operations" and "Gas Utility Operations." In total, the Utility occupies 9.3 million square feet, including approximately 975,000 square feet of leased office space. The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits or licenses from private landowners or governmental authorities.

The Utility currently owns approximately 170,000 acres of land, approximately 140,000 acres of which it will encumber with conservation easements or donate to public agencies or non-profit conservation organizations under the Settlement Agreement. Approximately 44,000 acres of this land may be either donated or encumbered with conservation easements. The remaining land contains the Utility's or a joint licensee's hydroelectric generation facilities and may only be encumbered with conservation easements. As contemplated in the Settlement Agreement, the Utility formed an entity, the Pacific Forest Watershed Lands Stewardship Council, or the Council. The Utility has appointed one out of 18 members of the board of directors of the Council. Other board members include representatives of federal and state agencies, non-governmental organizations, and tribal interests. The Council will recommend a plan to preserve the 140,000 acres to the Utility by April 2007. If the Council reaches consensus on the plan, the Utility will seek regulatory approval of the transactions required to implement the plan. If the Council is unable to reach consensus on all or part of the plan, the Utility will seek regulatory approval of the transactions required to implement its own plan, along with a description of the positions of the disputing board members.

PG&E Corporation also leases approximately 74,000 square feet of office space from a third party in San Francisco, California. This lease expires in 2012.

Item 3. *Legal Proceedings.*

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business.

Pacific Gas and Electric Company Chapter 11 Filing

On April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, in the U.S. Bankruptcy Court for the Northern District of California. On April 12, 2004, the Utility's plan of reorganization under Chapter 11 became effective.

On this date, the effective date, the Utility emerged from Chapter 11. On the effective date, the Utility paid all valid claims, deposited funds into escrow accounts for the payment of disputed claims upon their resolution, reinstated certain obligations, and paid other obligations.

David A. Coulter, a director of the Utility, is Vice Chairman of J.P. Morgan Chase & Co. and J.P. Morgan Chase Bank. J.P. Morgan Trust Co. of Delaware submitted a proof of claim in the Utility's Chapter 11 case for approximately \$1.45 million relating to its ownership interest in shares of the Utility's preferred stock. The bankruptcy court disallowed this claim. J.P. Morgan Chase Bank submitted a proof of claim for approximately \$173 million, related to its provision of a stand-by letter of credit which provides credit and liquidity support for certain of the Utility's pollution control bonds. This claim was paid upon the Effective Date of the Utility's plan of reorganization. Both entities are subsidiaries of J.P. Morgan Chase & Co.

The Utility's plan of reorganization incorporated the terms of the settlement agreement approved by the CPUC on December 18, 2003, and entered into among the CPUC, the Utility and PG&E Corporation on December 19, 2003, to resolve the Utility's Chapter 11 proceeding, or Settlement Agreement. Under the Settlement Agreement, the CPUC has waived all existing and future rights of sovereign immunity, and all other similar immunities, as a defense in connection with any action or proceeding concerning the enforcement of, or other determination of the parties' rights under the Settlement Agreement, the plan of reorganization or the confirmation order. The CPUC also consented to the jurisdiction of any court or other tribunal or forum for those actions or proceedings, including the bankruptcy court. The CPUC's waiver is irrevocable and applies to the jurisdiction of any court, legal process, suit, judgment, attachment in aid of execution of a judgment, attachment before judgment, set-off or any other legal process with respect to the enforcement of, or other determination of the parties' rights under, the Settlement Agreement, the plan of reorganization or the confirmation order. The Settlement Agreement contemplates that neither the CPUC nor any other California entity acting on its behalf may assert immunity in an action or proceeding concerning the parties' rights under the Settlement Agreement, the plan of reorganization or the confirmation order.

The Settlement Agreement generally terminates nine years after the effective date of the plan of reorganization, except that the rights of the parties to the Settlement Agreement that vest on or before termination, including any rights arising from any default under the Settlement Agreement, will survive termination for the purpose of enforcement. The parties agreed that the bankruptcy court will have jurisdiction over the parties for all purposes relating to enforcement of the Settlement Agreement, the plan of reorganization and the confirmation order. The bankruptcy court retains jurisdiction to resolve remaining disputed claims. The parties also agreed that the Settlement Agreement, the plan of reorganization or any order entered by the bankruptcy court contemplated or required to implement the Settlement Agreement or the plan of reorganization will be irrevocable and binding on the parties and enforceable under federal law notwithstanding any future decisions or orders of the CPUC.

On March 16, 2004, the CPUC denied separate applications that had been filed by the City of Palo Alto, the City and County of San Francisco, or CCSF, and Aglet Consumer Alliance, or Aglet, requesting that the CPUC rehear and reconsider its December 18, 2003 decision approving the Settlement Agreement. CCSF, Aglet and the CPUC's Office of Ratepayer Advocates, or ORA, also filed a joint application for rehearing. On April 15, 2004, CCSF and Aglet each filed a petition with the California Court of Appeal seeking review of the CPUC's December 18, 2003 decision approving the Settlement Agreement and the CPUC's March 16, 2004 decision denying applications for rehearing of its December 18, 2003 decision. CCSF and Aglet allege that the Settlement Agreement violates California law, among other claims. CCSF requests that the appellate court hear and review the CPUC's decisions, approving the Settlement Agreement and Aglet requests that the CPUC's decisions be overturned. Three California state senators have filed a brief in support of the CCSF and Aglet petitions. The California Court of Appeal has not yet acted on the petitions. PG&E Corporation and the Utility believe the petitions are without merit and should be denied.

On July 15, 2004, the U.S. District Court for the Northern District of California, or the District Court, dismissed the appeals of the bankruptcy court's confirmation order that had been filed by the two CPUC commissioners who did not vote to approve the Settlement Agreement. These two commissioners also appealed the District Court's order with the U.S. Court of Appeals for the Ninth Circuit. An appeal of the confirmation order filed by the City of Palo Alto remains pending at the District Court. PG&E Corporation and the Utility believe the appeals of the confirmation order are without merit.

Under applicable federal precedent, once the plan of reorganization has been "substantially consummated," any pending appeals of the confirmation order should be dismissed. If, notwithstanding this federal precedent, the bankruptcy court's confirmation order or the Settlement Agreement is subsequently overturned or modified, PG&E Corporation and the Utility's financial condition and results of operations could be materially adversely affected.

Pacific Gas and Electric Company vs. Michael Peevey, et al.

On November 8, 2000, the Utility filed a lawsuit in the District Court against the CPUC commissioners. In this lawsuit, the Utility seeks a declaration that the federally tariffed wholesale electricity costs that the Utility had incurred to serve the Utility's customers are recoverable in retail rates under the federal filed rate doctrine.

The Utility's complaint alleges that the wholesale electricity costs that the Utility has prudently incurred are paid pursuant to filed tariffs that the FERC has authorized and approved, and that, under the U.S. Constitution and numerous court decisions, such costs cannot be disallowed by state regulators. The Utility's complaint also alleges that, to the extent that the Utility is denied recovery of these wholesale electricity costs by order of the CPUC, such action constitutes an unlawful taking and confiscation of the Utility's property. The Utility argues that the CPUC's decisions are preempted by federal law under the filed rate doctrine, which requires the CPUC to allow the Utility to recover in full its reasonable purchase costs incurred under lawful rates and tariffs approved by the FERC, a federal governmental agency. The complaint also asserts claims under the Commerce Clause and the Due Process Clause of the U.S. Constitution. On January 29, 2001, the Utility's lawsuit was transferred to the U.S. District Court for the Central District of California, where a similar lawsuit filed by Southern California Edison Company was pending. On May 2, 2001, the court dismissed the Utility's complaints without prejudice to re-filing at a later date, on the ground that the lawsuit was premature, since two CPUC decisions referenced in the complaint had not become final under California law. The court rejected all of the CPUC's other arguments for dismissal of the Utility's complaint.

In August 2001, the Utility re-filed the Utility's complaint in the District Court based on the Utility's belief that the CPUC decisions referenced in the court's May 2001 order had become final under California law. On October 31, 2001, the CPUC moved to dismiss the action. While the motion was under submission, the parties filed cross-motions for summary judgment.

On July 25, 2002, the court denied the CPUC's motion to dismiss on all grounds, as well as the parties' motions for summary judgment. While the court agreed with the Utility's position that the filed rate doctrine applies to the federally-tariffed wholesale costs at which the Utility had purchased electricity, it held that certain triable issues of fact precluded entry of summary judgment in the Utility's favor.

On August 23, 2002, the CPUC filed an appeal to the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit. Pursuant to the Utility's request, the District Court certified the appeal as "wholly without merit and, therefore, frivolous," and rejected the CPUC's request to stay the proceedings. On November 21, 2002, the Ninth Circuit stayed the District Court's proceedings pending the CPUC's appeal. The appeal was fully briefed and the Ninth Circuit heard oral argument on March 10, 2003.

Under the Settlement Agreement, the Utility agreed to dismiss the filed rate case with prejudice on or as soon as practicable after the later of the effective date of the plan of reorganization and the date on which CPUC approval of the Settlement Agreement is no longer subject to appeal. On August 11, 2003, the Ninth Circuit issued an order staying proceedings in the filed rate case as requested by the Utility. The Utility has not yet dismissed its complaint, pending the outcome of the appeals of the CPUC's approval of the Settlement Agreement discussed above.

Diablo Canyon Power Plant

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system, which is regulated under a NPDES permit issued by the Central Coast Regional Water Quality Control Board, or Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility reached a tentative settlement of this matter with the Central Coast Board pursuant to which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Utility's Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available as defined in the Federal Clean Water Act. As part of the Central Coast settlement agreement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately \$6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the Central Coast settlement agreement. On June 17, 2003, the Central Coast settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement is that the Central Coast Board renew Diablo Canyon's NPDES permit.

At its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the Central Coast settlement agreement accepted in March 2003, and the Central Coast Board requested a team of independent scientists, as part of a technical working group, to develop additional information on possible mitigation measures for Central Coast Board staff. In January 2005, the Central Coast Board published the scientists' draft report recommending several such mitigation measures. If the Central Coast Board adopts the scientists' recommendations, and if the Utility ultimately is required to implement the projects proposed in the draft report, it could incur costs of up to approximately \$30 million. The Utility would seek to recover these costs through rates charged to customers.

The Utility believes that the ultimate outcome of this matter will not have a material adverse impact on the Utility's financial condition or results of operations.

Complaints Filed by the California Attorney General and the City and County of San Francisco

On January 10, 2002, the California Attorney General filed a complaint in the San Francisco Superior Court, or Superior Court, against PG&E Corporation and its directors, as well as against directors of the Utility, based on allegations of unfair or fraudulent business acts or practices in violation of California Business and Professions Code Section 17200, or Section 17200. Among other allegations, the California Attorney General alleged that past transfers of money from the Utility to PG&E Corporation, and allegedly from PG&E Corporation to other affiliates of PG&E Corporation,

violated various conditions established by the CPUC in decisions approving the holding company formation. The California Attorney General alleged that the defendants violated these conditions when PG&E Corporation allegedly failed to provide adequate financial support to the Utility during the California energy crisis. The California Attorney General also alleged that the December 2000 and January and February 2001 ringfencing transactions, by which PG&E Corporation subsidiaries complied with credit rating agency criteria to establish independent credit ratings, violated the holding company conditions.

The complaint seeks injunctive relief, the appointment of a receiver, restitution in an amount according to proof, civil penalties of \$2,500 against each defendant for each violation of Section 17200, a total penalty of not less than \$500 million and costs of suit. The California Attorney General's complaint also seeks restitution of assets allegedly wrongfully transferred to PG&E Corporation from the Utility. In February 2002, PG&E Corporation filed a notice of removal in the bankruptcy court to transfer the California Attorney General's complaint to the bankruptcy court, as well as a motion to dismiss the lawsuit, or in the alternative, to stay the suit with the bankruptcy court. Subsequently, the California Attorney General filed a motion to remand the action to state court. In June 2002, the bankruptcy court held that federal law preempted the California Attorney General's allegations concerning PG&E Corporation's participation in the Utility's Chapter 11 proceedings. The bankruptcy court directed the California Attorney General to file an amended complaint omitting these allegations and remanded the amended complaint to the Superior Court. Both parties appealed the bankruptcy court's June 2002 order to the District Court.

On August 9, 2002, the California Attorney General filed its amended complaint in the Superior Court, omitting the allegations concerning PG&E Corporation's participation in the Utility's Chapter 11 proceedings.

On February 11, 2002, a complaint entitled *City and County of San Francisco; People of the State of California v. PG&E Corporation, and Does 1-150*, was filed in the Superior Court. The complaint contains some of the same allegations contained in the California Attorney General's complaint, including allegations of unfair competition. In addition, the complaint alleges causes of action for conversion, claiming that PG&E Corporation "took at least \$5.2 billion from the Utility," and for unjust enrichment. The City seeks injunctive relief, the appointment of a receiver, payment to customers, disgorgement, the imposition of a constructive trust, civil penalties and costs of suit.

After removing the City's action to the bankruptcy court in February 2002, PG&E Corporation filed a motion to dismiss the complaint. Subsequently, the City filed a motion to remand the action to state court. In June 2002, the bankruptcy court issued an amended order on motion to remand stating that the bankruptcy court retained jurisdiction over the causes of action for conversion and unjust enrichment, finding that these claims belong solely to the Utility and cannot be asserted by the City and County, but remanding the Section 17200 cause of action to state court. Both parties appealed the bankruptcy court's remand order to the District Court.

On October 8, 2003, the District Court reversed, in part, the bankruptcy court's June 2002 decision and ordered the California Attorney General's restitution claims sent back to the bankruptcy court. The District Court found that these claims, estimated along with the City and County of San Francisco's claims at approximately \$5 billion, are the property of the Utility's Chapter 11 estate and therefore are properly within the bankruptcy court's jurisdiction. Under the Plan of Reorganization, the Utility has released these claims. The District Court also affirmed, in part, the bankruptcy court's June 2002 decision and found that the California Attorney General's civil penalty and injunctive relief claims under Section 17200 could be resolved in Superior Court. The California Attorney General and the City and County of San Francisco have appealed this ruling to the Ninth Circuit, where the appeal is currently pending.

The Superior Court has coordinated the California Attorney General's case with the case filed by the City and County of San Francisco.

At a hearing on December 8, 2004, the Superior Court heard argument on the issue of how to determine the number of violations of Section 17200 for purposes of calculating the amount of potential civil penalties at issue. Under Section 17200, the Superior Court can impose a civil penalty for each violation of up to \$2,500. On January 21, 2005, the Superior Court issued a tentative decision rejecting the "per victim" and "per [customer] bill" approaches advocated by the plaintiffs, standards that potentially could have resulted in millions of separate "violations." The Superior Court found that the appropriate standard was each transfer of money from the Utility to PG&E Corporation that plaintiffs allege violated Section 17200.

The Superior Court stated that it would consider any non-substantive revisions to the tentative decision proposed by the parties at a case management conference to be held on February 25, 2005.

PG&E Corporation believes that the applicable calculation methodology for civil penalties, if any violations were found, would not result in a material adverse effect on its financial condition or results of operations.

Compressor Station Chromium Litigation

The following 14 civil suits are pending in several California courts against the Utility relating to alleged chromium contamination: (1) *Aguayo v. Pacific Gas and Electric Company*, filed March 15, 1995, in Los Angeles County Superior Court, (2) *Aguilar v. Pacific Gas and Electric Company*, filed October 4, 1996, in Los Angeles County Superior Court, (3) *Acosta, et al. v. Betz Laboratories, Inc., et al.*, filed November 27, 1996, in Los Angeles County Superior Court, (4) *Adams v. Pacific Gas and Electric Company and Betz Chemical Company*, filed July 25, 2000, in Los Angeles County Superior Court, (5) *Baldonado v. Pacific Gas and Electric Company*, filed October 25, 2000, in Los Angeles County Superior Court, (6) *Gale v. Pacific Gas and Electric Company*, filed January 30, 2001, in Los Angeles County Superior Court, (7) *Fordyce v. Pacific Gas and Electric Company*, filed March 16, 2001, in San Bernardino Superior Court, (8) *Puckett v. Pacific Gas and Electric Company*, filed March 30, 2001, in Los Angeles County Superior Court, (9) *Alderson, et al. v. PG&E Corporation, Pacific Gas and Electric Company, Betz Chemical Company, et al.*, filed April 11, 2001, in Los Angeles County Superior Court, (10) *Bowers, et al. v. Pacific Gas and Electric Company, et al.*, filed April 20, 2001, in Los Angeles County Superior Court, (11) *Boyd, et al. v. Pacific Gas and Electric Company, et al.*, filed May 2, 2001, in Los Angeles County Superior Court, (12) *Martinez, et al. v. Pacific Gas and Electric Company*, filed June 29, 2001, in San Bernardino County Superior Court, (13) *Miller v. Pacific Gas and Electric Company*, filed November 21, 2001, in Los Angeles County Superior Court, and (14) *Lytle v. Pacific Gas and Electric Company*, filed March 22, 2002, in Yolo County Superior Court.

All of these civil actions are now pending in the Los Angeles Superior Court, except the Lytle case, which is pending in Yolo County. Currently there are approximately 1,200 plaintiffs in the chromium litigation cases. Approximately 1,260 individuals have filed proofs of claim in the Utility's Chapter 11 case, most of whom are plaintiffs in the chromium litigation. Approximately 1,035 claimants have filed proofs of claim requesting approximately \$580 million in damages and another approximately 225 claimants have filed claims for an "unknown amount."

In general, plaintiffs and claimants allege that exposure to chromium at or near the Utility's gas compressor stations located at Kettleman and Hinkley, California, and the area of California near Topock, Arizona caused personal injuries, wrongful death, or other injury and seek related damages. The bankruptcy court has granted certain claimants' motions for relief from stay so that the state court lawsuits pending before the Utility's Chapter 11 filing can proceed.

The Utility is responding to the suits in which the Utility has been served and is asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including the statute of limitations, exclusivity of workers' compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

To assist in managing and resolving litigation with this many plaintiffs, the parties agreed to select plaintiffs from the *Aguayo*, *Acosta* and *Aguilar* cases for a test trial. Plaintiffs' counsel selected ten of these initial trial plaintiffs, defense counsel selected seven of the plaintiffs, and one plaintiff and two alternates were selected at random. The Utility has filed 14 summary judgment motions or motions in limine (motions to exclude potentially prejudicial information) challenging the claims of the trial test plaintiffs. The Los Angeles Superior Court began hearing argument on two of the motions in February 2004. At a hearing on February 14, 2005, the court indicated that it had signed orders denying these two motions, but the orders have not been delivered to the parties. The court set a trial date of January 9, 2006 for the first eighteen plaintiffs. The other motions will be heard throughout 2005.

The Utility has recorded a reserve in the Utility's financial statements in the amount of \$160 million for these matters. The Utility believes that, in light of the reserves that have already been accrued with respect to this matter, the ultimate outcome of this matter will not have a material adverse impact on the Utility's financial condition or future results of operations.

Item 4. Submission of Matters to a Vote of Security Holders

Not applicable.

EXECUTIVE OFFICERS OF THE REGISTRANTS

"The names, ages and positions of PG&E Corporation executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Securities and Exchange Act of 1934, or Exchange Act at December 31, 2004 are as follows:

Name	Age	Position
R. D. Glynn, Jr.	62	Chairman of the Board, Chief Executive Officer, and President
P. A. Darbee	51	Senior Vice President and Chief Financial Officer
L. H. Everett	54	Senior Vice President and Assistant to the Chairman
R. A. Jackson	47	Senior Vice President, Human Resources
C. P. Johns	44	Senior Vice President and Controller
T. B. King	43	Executive Vice President and Chief of Utility Operations, Pacific Gas and Electric Company
D. D. Richard, Jr.	54	Senior Vice President, Public Affairs
G. R. Smith	56	Senior Vice President; President and Chief Executive Officer, Pacific Gas and Electric Company
B. R. Worthington	55	Senior Vice President and General Counsel

All officers of PG&E Corporation serve at the pleasure of the Board of Directors. During the past five years through December 31, 2004, the executive officers of PG&E Corporation had the following business experience. Except as otherwise noted, all positions have been held at PG&E Corporation.

Effective January 1, 2005, Peter A. Darbee became President and Chief Executive Officer of PG&E Corporation replacing Mr. Glynn, who continues to serve as Chairman of the Board of Directors of each of PG&E Corporation and Pacific Gas and Electric Company. Mr. Darbee also became a director of PG&E Corporation and Pacific Gas and Electric Company on January 1, 2005. Also, effective January 1, 2005, Christopher P. Johns became Senior Vice President and Chief Financial Officer replacing Mr. Darbee. Mr. Johns continues to be the Controller of PG&E Corporation. Effective January 1, 2005, Ms. Everett became Senior Vice President and Assistant to the Chief Executive Officer.

Name	Position	Period Held Office
R. D. Glynn, Jr.	Chief Executive Officer and President of PG&E Corporation Chairman of the Board, PG&E Corporation and Pacific Gas and Electric Company	January 1, 1998 to December 31, 2004 January 1, 1998 to present
P. A. Darbee	Senior Vice President and Chief Financial Officer Senior Vice President, Chief Financial Officer, and Treasurer	July 9, 2001 to December 31, 2004 September 20, 1999 to July 8, 2001
L. H. Everett	Senior Vice President and Assistant to the Chairman Vice President and Assistant to the Chairman Vice President, Corporate Secretary, and Assistant to the Chairman Vice President and Corporate Secretary Vice President and Corporate Secretary, Pacific Gas and Electric Company	August 2, 2004 to December 31, 2004 June 1, 2001 to August 1, 2004 May 1, 2001 to May 31, 2001 July 1, 1997 to April 30, 2001 November 1, 1996 to April 30, 2001
R. A. Jackson	Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company Vice President, Human Resources, PG&E Corporation Vice President, Human Resources, Pacific Gas and Electric Company	August 2, 2004 to present June 1, 2004 to August 1, 2004 June 1, 1999 to August 1, 2004
C. P. Johns	Senior Vice President and Controller Vice President and Controller Vice President and Controller, Pacific Gas and Electric Company	September 19, 2001 to December 31, 2004 July 1, 1997 to September 18, 2001 June 1, 1996 to December 31, 1999
T. B. King	Executive Vice President and Chief of Utility Operations, Pacific Gas and Electric Company Senior Vice President and Chief of Utility Operations, Pacific Gas and Electric Company Senior Vice President, PG&E Corporation President, PG&E National Energy Group, Inc. President and Chief Operating Officer, PG&E Gas Transmission Corporation President and Chief Operating Officer, Gas Transmission, PG&E National Energy Group, Inc. President and Chief Operating Officer, West Region, PG&E National Energy Group, Inc. President and Chief Operating Officer, PG&E Gas Transmission Corporation	August 2, 2004 to present November 1, 2003 to August 1, 2004 January 1, 1999 to October 31, 2003 November 15, 2002 to July 8, 2003 August 27, 2002 to July 8, 2003 August 9, 2002 to November 14, 2002 July 1, 2000 to August 8, 2002 November 23, 1998 to September 10, 2002
D. D. Richard, Jr	Senior Vice President, Public Affairs Vice President, Governmental Relations Senior Vice President, Public Affairs, Pacific Gas and Electric Company	October 18, 2000 to present July 1, 1997 to October 17, 2000 May 1, 1998 to present

G.R. Smith	Senior Vice President President and Chief Executive Officer, Pacific Gas and Electric Company	January 1, 1999 to present June 1, 1997 to present
B. R. Worthington	Senior Vice President and General Counsel	June 1, 1997 to present

The names, ages and positions of the Utility's "executive officers," as defined by Rule 3b-7 of the General Rules and Regulations under the Exchange Act at December 31, 2004 are as follows:

Name	Age	Position
R.D. Glynn, Jr.	62	Chairman of the Board of Directors
G. R. Smith	56	President and Chief Executive Officer
T. B. King	43	Executive Vice President and Chief of Utility Operations
P.A. Darbee	51	Senior Vice President and Chief Financial Officer of PG&E Corporation
L.H. Everett	54	Senior Vice President and Assistant to the Chairman, PG&E Corporation
K. M. Harvey	46	Senior Vice President—Chief Financial Officer, and Treasurer
R.M. Jackson	47	Senior Vice President, Human Resources
R. J. Peters	54	Senior Vice President and General Counsel
D. D. Richard, Jr.	54	Senior Vice President, Public Affairs
G. M. Rueger	54	Senior Vice President, Generation and Chief Nuclear Officer
B. R. Worthington	55	Senior Vice President and General Counsel, PG&E Corporation

All officers of the Utility serve at the pleasure of the Board of Directors. During the past five years through December 31, 2004, the executive officers of the Utility had the following business experience. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

Name	Position	Period Held Office
R. D. Glynn, Jr.	Chief Executive Officer and President, PG&E Corporation Chairman of the Board, Pacific Gas and Electric Company and PG&E Corporation	January 1, 1998 to December 31, 2004 January 1, 1998 to present
G. R. Smith	President and Chief Executive Officer Senior Vice President, PG&E Corporation	June 1, 1997 to present January 1, 1999 to present
T. B. King	Executive Vice President and Chief of Utility Operations Senior Vice President and Chief of Utility Operations Senior Vice President, PG&E Corporation President, PG&E National Energy Group, Inc. President and Chief Operating Officer, PG&E Gas Transmission Corporation President and Chief Operating Officer, Gas Transmission, PG&E National Energy Group, Inc. President and Chief Operating Officer, West Region, PG&E National Energy Group, Inc. President and Chief Operating Officer, PG&E Gas Transmission Corporation	August 2, 2004 to present November 1, 2003 to August 1, 2004 January 1, 1999 to October 31, 2003 November 15, 2002 to July 8, 2003 August 27, 2002 to July 8, 2003 August 9, 2002 to November 14, 2002 July 1, 2000 to August 8, 2002 November 23, 1998 to September 10, 2002

P. A. Darbee	Senior Vice President and Chief Financial Officer, PG&E Corporation	July 9, 2001 to December 31, 2004
	Senior Vice President, Chief Financial Officer, and Treasurer, PG&E Corporation	September 20, 1999 to July 8, 2001
L. H. Everett	Senior Vice President and Assistant to the Chairman, PG&E Corporation	August 2, 2004 to December 31, 2004
	Vice President and Assistant to the Chairman, PG&E Corporation	June 1, 2001 to August 1, 2004
	Vice President, Corporate Secretary, and Assistant to the Chairman, PG&E Corporation	May 1, 2001 to May 31, 2001
	Vice President and Corporate Secretary, PG&E Corporation	July 1, 1997 to April 30, 2001
	Vice President and Corporate Secretary	November 1, 1996 to April 30, 2001
K. M. Harvey	Senior Vice President, Chief Financial Officer, and Treasurer	November 1, 2000 to present
	Senior Vice President, Chief Financial Officer, Controller, and Treasurer	January 1, 2000 to October 31, 2000
R. A. Jackson	Senior Vice President, Human Resources, Pacific Gas and Electric Company and PG&E Corporation	August 2, 2004 to present
	Vice President, Human Resources, PG&E Corporation	June 1, 2004 to August 1, 2004
	Vice President, Human Resources	June 1, 1999 to August 1, 2004
R. J. Peters	Senior Vice President and General Counsel	January 1, 1999 to present
D. D. Richard, Jr.	Senior Vice President, Public Affairs	May 1, 1998 to present
	Senior Vice President, Public Affairs, PG&E Corporation	October 18, 2000 to present
	Vice President, Governmental Relations, PG&E Corporation	July 1, 1997 to October 17, 2000
G. M. Rueger	Senior Vice President, Generation and Chief Nuclear Officer	April 2, 2000 to present
	Senior Vice President and General Manager, Nuclear Power Generation Business Unit	November 1, 1991 to April 1, 2000
B. R. Worthington	Senior Vice President and General Counsel, PG&E Corporation	June 1, 1997 to present

PART II

Item 5. *Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

(a) Information responding to part of Item 5, for each of PG&E Corporation and Pacific Gas and Electric Company, is set forth under the heading "Quarterly Consolidated Financial Data (Unaudited)" in the 2004 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report. As of February 15, 2005, there were 103, 707 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed principally on the New York Stock Exchange. PG&E Corporation common stock also is listed on the Pacific Exchange and the Swiss stock exchanges. The discussion of dividends with respect to PG&E Corporation's common stock is hereby incorporated by reference from "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Financial Resources—Dividends" of the 2004 Annual Report.

As previously disclosed, in connection with its entry into certain credit agreements, in June 2002 and October 2002, PG&E Corporation issued warrants to purchase 5,066,931 shares of common stock of PG&E Corporation at an exercise price of \$0.01 per share. During the quarter ended December 31, 2004, warrant holders exercised, on a net exercise basis, warrants to purchase 961,480 shares, and received 961,183 shares of PG&E Corporation common stock. As of December 31, 2004, warrant holders had exercised, on a net exercise basis, warrants to purchase 4,719,019 shares, and had received 4,717,290 shares of PG&E Corporation common stock since the warrants were issued.

Pacific Gas and Electric Company did not make any sales of unregistered equity securities during 2004, the period covered by this report.

(b) *Issuer Purchases of Equity Securities*

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs ⁽¹⁾⁽²⁾⁽³⁾	Approximate Dollar Value that may yet be Purchased Under the Plans or Programs
October 1 through October 31, 2004	—	—	—	\$ 350,000,000
November 1 through November 30, 2004	340,000	\$ 33.5676	340,000	\$ 350,000,000
December 1 through December 31, 2004	11,293,200	\$ 32.4493	11,293,200	—
Total	11,633,200 ⁽⁴⁾	\$ 32.4820	11,633,200	\$ —

- (1) On September 15, 2004, the PG&E Corporation Board of Directors authorized the Corporation and its subsidiaries to repurchase shares of PG&E Corporation's common stock with an aggregate purchase price not to exceed PG&E Corporation's net cash proceeds from sales of PG&E Corporation's common stock upon exercise of options granted under PG&E Corporation's Stock Option Plan. The program was publicly announced in a Form 8-K filed by PG&E Corporation on October 14, 2004. Repurchases may be made from time until the program expires on December 31, 2005. Amounts remaining under this program are not determinable as PG&E Corporation cannot predict how many options will be exercised before December 31, 2005.
- (2) Also on September 15, 2004, the PG&E Corporation Board of Directors authorized the Corporation and its subsidiaries to repurchase up to \$350 million in shares of PG&E Corporation's common stock. The program was publicly announced in a Form 8-K filed by PG&E Corporation on October 14, 2004. As of December 13, 2004, when PG&E Corporation terminated its open market stock purchase program, PG&E Corporation had used approximately \$32 million of the previously announced \$350 million authorization to repurchase shares. As disclosed in a Form 8-K filed on December 16, 2004, PG&E Corporation entered into accelerated share repurchase arrangements with a broker on December 15, 2004, under which PG&E Corporation used the remaining approximately \$318 million to repurchase shares of its common stock on an accelerated basis.
- (3) On December 15, 2004, the PG&E Corporation Board of Directors authorized the Corporation and its subsidiaries to repurchase up to \$975 million in shares of PG&E Corporation's common stock. The program was publicly announced in a Form 8-K filed by PG&E Corporation on December 16, 2004. As disclosed in a Form 8-K filed on December 23, 2004, PG&E Corporation entered into accelerated share repurchase arrangements with a broker on December 23, 2004, but provided notice of termination of these arrangements on January 31, 2005, effective on February 1, 2005. PG&E Corporation did not repurchase any shares of its common stock under this program.

- (4) Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation, purchased 850,000 shares of PG&E Corporation common stock during the fourth quarter. These shares remain outstanding under California law although for accounting purposes they are treated as if they were treasury shares.

Item 6. *Selected Financial Data*

A summary of selected financial information, for each of PG&E Corporation and Pacific Gas and Electric Company for each of the last five fiscal years, is set forth under the heading "Selected Financial Data" in the 2004 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 7. *Management's Discussion and Analysis of Financial Condition and Results of Operations*

A discussion of PG&E Corporation's and Pacific Gas and Electric Company's consolidated results of operations and financial condition is set forth on under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations" in the 2004 Annual Report, which discussion is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 7A. *Quantitative and Qualitative Disclosures About Market Risk*

Information responding to Item 7A appears in the 2004 Annual Report under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations—Risk Management Activities," and under Notes 1 and 8 of the "Notes to the Consolidated Financial Statements" of the 2004 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 8. *Financial Statements and Supplementary Data*

Information responding to Item 8 appears in the 2004 Annual Report under the following headings for PG&E Corporation: "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity;" under the following headings for Pacific Gas and Electric Company: "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity;" and under the following headings for PG&E Corporation and Pacific Gas and Electric Company jointly: "Notes to the Consolidated Financial Statements," "Quarterly Consolidated Financial Data (Unaudited)," "Independent Auditors' Report," and "Responsibility for the Consolidated Financial Statements," which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 9. *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

Not applicable.

Item 9A. *Controls and Procedures*

Based on an evaluation of PG&E Corporation's and Pacific Gas and Electric Company's, or the Utility's, disclosure controls and procedures as of December 31, 2004, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures are effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports the companies file or submit under the Securities and Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission rules and forms.

As of January 1, 2004, PG&E Corporation and the Utility adopted the Financial Accounting Standards Board's, or FASB, revision to FASB Interpretation No. 46, "Consolidation of Variable Interest Entities," or FIN 46R. In accordance with FIN 46R, the Utility consolidated the assets, liabilities and non-controlling interests of low-income housing partnerships that were determined to be variable interest entities, or VIEs, under FIN 46R. PG&E Corporation and the Utility do not have the legal right or authority to assess the internal controls of VIEs. Therefore, PG&E Corporation and the Utility's evaluation of disclosure controls and procedures performed as of December 31, 2004 did not include these entities in that evaluation. PG&E Corporation and the Utility have not designed, established, or maintained disclosure controls and procedures for consolidated VIEs.

There were no changes in internal controls over financial reporting that occurred during the quarter ended December 31, 2004 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's controls over financial reporting.

Management of PG&E Corporation and the Utility have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in the 2004 Annual Report under the heading "Management's Report on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm," which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Item 9B. Other Information

Nomination for Election as Directors

On February 16, 2005, the Nominating, Compensation and Governance Committee of the Board of Directors of PG&E Corporation, or the Committee, nominated the following individuals for election as directors of PG&E Corporation to be voted on at the 2005 annual meeting of shareholders: David R. Andrews, Leslie S. Biller, David A. Coulter, C. Lee Cox, Peter A. Darbee, Robert D. Glynn, Jr., Mary S. Metz, Barbara L. Rambo, and Barry Lawson Williams. The Committee also nominated the same nine individuals for election as directors of the Utility, in addition to Gordon R. Smith. One of the current members of the Boards of Directors, David M. Lawrence, MD, will retire from the Board of Directors of PG&E Corporation and the Utility effective at the adjournment of the 2005 joint annual meeting of the shareholders of PG&E Corporation and Utility, and has not been nominated for re-election to the Boards.

Amendment of Bylaws

On February 16, 2005, the Board of Directors of PG&E Corporation adopted resolutions to amend the PG&E Corporation bylaws to decrease the authorized number of directors from ten to nine, effective at the adjournment of the annual meeting of shareholders to be held on April 20, 2005. Under PG&E Corporation's bylaws, the authorized number of directors may not be less than 7 nor more than 13, but within that range the Board of Directors may set the exact number of directors by an amendment to the bylaws. The text of the bylaw amendment follows:

1. **Number.** As stated in paragraph I of Article Third of this Corporation's Articles of Incorporation, the Board of Directors of this Corporation shall consist of such number of directors, not less than seven (7) nor more than thirteen (13). The exact number of directors shall be nine (9) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

On February 16, 2005, the Board of Directors of the Utility also adopted resolutions to amend the Utility bylaws to decrease the authorized number of directors from eleven to ten, effective at the adjournment of the annual meeting of shareholders to be held on April 20, 2005. Under the Utility's

bylaws, the authorized number of directors may not be less than 9 nor more than 17, but within that range the Board of Directors may set the exact number of directors by an amendment to the bylaws. The text of the bylaw amendment follows:

1. **Number.** The Board of Directors of this Corporation shall consist of such number of directors, not less than nine (9) nor more than seventeen (17). The exact number of directors shall be ten (10) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

Approval of Performance Scale under 2005 Short Term Incentive Plan

As previously disclosed, the Committee has approved the structure of the 2005 Short-Term Incentive Plan (STIP) under which officers of PG&E Corporation and the Utility are provided an opportunity to receive annual incentive cash payments. For PG&E Corporation executive officers, the STIP award will be based entirely on the achievement of financial objectives, as measured by earnings from operations. The executive officers of the Utility will have an opportunity to receive annual cash incentives based on three criteria: the achievement of financial objectives as measured by PG&E Corporation's earnings from operations (weighted 25%), the Utility's contribution to PG&E Corporation's earnings from operations (weighted 50%), and the success of key strategic initiatives (weighted 25%). At its meeting on February 16, 2005, the Committee approved the specific performance scale that will be used to determine the extent to which the corporate financial objective, as measured by earnings from operations, has been met.

The Committee used the same methodology to establish the performance scale for the 2005 STIP as was used for the 2004 STIP. The corporate financial performance measure is based on PG&E Corporation's budgeted earnings from operations that were previously approved by the Board of Directors, consistent with the basis for reporting and guidance to the financial community. As with previous earnings performance scales, unbudgeted items impacting comparability such as changes in accounting methods, workforce restructuring, and one-time occurrences will be excluded. The Committee will continue to retain full discretion as to the determination of final officer STIP awards.

PART III

Item 10. Directors and Executive Officers of the Registrant

Information regarding executive officers of PG&E Corporation and Pacific Gas and Electric Company is included in a separate item captioned "Executive Officers of the Registrants" contained on pages 49 through 52 in Part I of this report. Other information responding to Item 10 is included under the heading "Item No. 1: Election of Directors of PG&E Corporation and Pacific Gas and Electric Company" and under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Proxy Statement relating to the 2005 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Website Availability of Corporate Governance and Other Documents

The following documents are available both on PG&E Corporation's website www.pgecorp.com, and Pacific Gas and Electric Company's website, www.pge.com: (1) the codes of conduct and ethics adopted by PG&E Corporation and Pacific Gas and Electric Company applicable to their respective directors and employees, including their respective Chief Executive Officers, Chief Financial Officers, Controllers, and other executive officers, (2) PG&E Corporation's and Pacific Gas and Electric Company's corporate governance guidelines, and (3) key Board Committee charters, including charters for the companies' Audit Committees and the PG&E Corporation Nominating, Compensation, and Governance Committee. Shareholders also may obtain print copies of these documents by submitting a written request to Linda Y.H. Cheng, Corporate Secretary of both PG&E Corporation and Pacific Gas and Electric Company, One Market, Spear Tower, Suite 2400, San Francisco, California 94105.

If any amendments are made to, or any waivers are granted with respect to, provisions of the codes of conduct and ethics adopted by PG&E Corporation and Pacific Gas and Electric Company that apply to their respective Chief Executive Officers, Chief Financial Officers or Controllers, the company whose code is so affected will disclose the nature of such amendment or waiver on its respective website and any waivers to the code will be disclosed in a Current Report on Form 8-K filed within 5 days of the waiver.

Item 11. Executive Compensation

Information responding to Item 11, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading "Compensation of Directors" and under the headings "Summary Compensation Table," "Option/SAR Grants in 2004," "Aggregated Option/SAR Exercises in 2004 and Year-End Option/SAR Values," "Long-Term Incentive Program—Awards in 2004," "Retirement Benefits," "Employment Contracts Termination of Employment, and Change In Control Provisions" in the Joint Proxy Statement relating to the 2005 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Information responding to Item 12, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading "Security Ownership of Management" and under the heading "Principal Shareholders" in the Joint Proxy Statement relating to the 2005 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Equity Compensation Plan Information

The following table provides information as of December 31, 2004, concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corporation's existing equity compensation plans.

Plan Category	(a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights	(b) Weighted Average Exercise Price of Outstanding Options, Warrants, and Rights	(c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column(a))
Equity compensation plans approved by shareholders	21,021,916	\$ 22.76	10,439,785(1)
Equity compensation plans not approved by shareholders	—	\$ —	—
Total equity compensation plans	21,021,916	\$ 22.76	10,439,785

- (1) Represents the total number of shares available for issuance under PG&E Corporation's Long-Term Incentive Program (LTIP) as of December 31, 2004. Outstanding stock-based awards granted under the LTIP include stock options, restricted stock, and phantom stock payable in an equal number of shares upon termination of employment or service as a director. No more than 5,000,000 of the reserved shares under the LTIP may be awarded as restricted stock. For a description of the LTIP, see Note 10 of the Notes to the Consolidated Financial Statements in the Annual Report.

Item 13. Certain Relationships and Related Transactions

Information responding to Item 13, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading "Certain Relationships and Related Transactions" in the Joint Proxy Statement relating to the 2005 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Item 14. Principal Accountant Fees and Services

Information responding to Item 14, for each of PG&E Corporation and Pacific Gas and Electric Company, is included under the heading "Information Regarding the Independent Public Accountants of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement relating to the 2005 Annual Meetings of Shareholders, which information is hereby incorporated by reference.

Item 15. Exhibits and Financial Statement Schedules**(a) The following documents are filed as a part of this report:**

1. The following consolidated financial statements, supplemental information, and independent auditors' report are contained in the 2004 Annual Report, which have been incorporated by reference in this report:

Consolidated Statements of Operations for the Years Ended December 31, 2004, 2003, and 2002, for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2004, and 2003 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Common Shareholders' Equity for the Years Ended December 31, 2004, 2003, and 2002, for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2004, 2003, and 2002 for Pacific Gas and Electric Company.

Notes to Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Report of Independent Registered Public Accounting Firm (Deloitte & Touche LLP).

2. Report of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) included at page 66 of this Form 10-K.
3. Financial statement schedules:

I—Condensed Financial Information of Parent as of December 31, 2004 and 2003 and for the Years Ended December 31, 2004, 2003, and 2002.

II—Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2004, 2003, and 2002.

Schedules not included are omitted because of the absence of conditions under which they are required or because the required information is provided in the consolidated financial statements including the notes thereto.

4. Exhibits required to be filed by Item 601 of Regulation S-K:

Exhibit Number	Exhibit Description
2.1	Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1)

- 2.2 Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2)
- 3.1 Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1)
- 3.2 Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)
- 3.3 Bylaws of PG&E Corporation amended as of January 1, 2005
- 3.4 Bylaws of PG&E Corporation amended as of April 20, 2005
- 3.5 Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3)
- 3.6 Bylaws of Pacific Gas and Electric Company amended as of January 1, 2005
- 3.7 Bylaws of Pacific Gas and Electric Company amended as of April 20, 2005
- 4.1 Indenture of Mortgage, dated as of March 11, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1)
- 4.2 First Supplemental Indenture, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4.2)
- 4.3 Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4)
- 4.4 Escrow Deposit and Disbursement Agreement, dated as of March 23, 2004, among Pacific Gas and Electric Company and BNY Western Trust Company as escrow agent and trustee (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4.3)
- 4.5 Calculation Agency Agreement, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4.4)
- 4.6 Indenture related to PG&E Corporation's 7.5% Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.1).

- 4.7 Supplemental Indenture related to PG&E Corporation's 9.50% Convertible Subordinated Notes due June 2010, dated as of October 18, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1)
- 4.8 Warrant Agreement, dated as of June 25, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.9).
- 4.9 Warrant Agreement, dated as of October 18, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.2)
- 10.1 Credit Agreement dated as of March 5, 2004, among Pacific Gas and Electric Company, as borrower, the Several Lenders from time to time parties thereto, Citicorp North America, Inc., as Administrative Agent, Banc One Capital Markets, Inc., as Syndication Agent, and Lehman Commercial Paper Inc., Credit Suisse First Boston, acting through its Cayman Islands Branch, and UBS Securities LLC, as Co- Documentation Agents (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 10, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 99)
- 10.2 Credit Agreement, dated as of December 10, 2004, among PG&E Corporation, BNP Paribas, as administrative agent and a lender, Deutsche Bank Securities, as syndication agent, ABN Amro Bank, N.V., Goldman Sachs Credit Partners L.P., and Union Bank of California, N.A., as documentation agents and lenders, and the following other lenders: Barclays Bank PLC, Citicorp USA, Inc., Deutsche Bank AG New York Branch, JP Morgan Chase Bank, N.A., Lehman Brothers Bank, FSB, Morgan Stanley Bank, Royal Bank of Canada, The Bank of Nova Scotia, and The Bank of New York (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed December 15, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 99.)
- 10.3 Master Confirmation dated December 15, 2004, for accelerated share repurchase arrangements between PG&E Corporation and Goldman, Sachs & Co.
- 10.4 Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 99)
- 10.5 Firm Transportation Service Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated October 26, 1993, Rate Schedule FTS-1, and general terms and conditions (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.4)
- 10.6 Operating Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated July 9, 1996 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.5)

- 10.7 PG&E Trans-User Agreement between Pacific Gas and Electric Company and PG&E Gas Transmission, Northwest Corporation dated November 15, 1999 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.6)
- 10.8 Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, initially effective March 31, 1998, as amended to date (CAISO, FERC Electric Tariff No. 7)
- 10.9 Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company
- *10.10 PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004
- *10.11 PG&E Corporation Supplemental Retirement Savings Plan effective as of January 1, 2005
- *10.12 Description of Compensation Arrangement between PG&E Corporation and Peter Darbee (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.3)
- *10.13 Letter regarding Compensation Arrangement between PG&E Corporation and Peter A. Darbee effective June 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.4)
- *10.14 Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated November 4, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.6)
- *10.15 Letter Regarding Relocation Arrangement Between PG&E Corporation and Thomas B. King dated March 16, 2000 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 10)
- *10.16 Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated June 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.3)
- *10.17 PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005
- *10.18 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2005
- *10.19 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.24)
- *10.20 Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended effective as of December 31, 2004, and frozen as of January 1, 2005
- *10.21 Supplemental Executive Retirement Plan of PG&E Corporation effective January 1, 2005
- *10.22.1 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Robert D. Glynn, Jr. dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.1)

- *10.22.2 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.2)
- *10.22.3 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gregory M. Rueger dated December 20, 2002 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2002 (File No. 1-12609 and File No. 1-2348), Exhibit 10.37.3)
- *10.22.4 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gordon R. Smith dated December 20, 2002 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2002 (File No. 1-12609 and File No. 1-2348), Exhibit 10.37.4)
- *10.22.5 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and James K. Randolph dated December 20, 2002 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2002 (File No. 1-12609 and File No. 1-2348), Exhibit 10.37.5)
- *10.23.1 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Robert D. Glynn, Jr. dated April 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.2.1)
- *10.23.2 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gordon R. Smith dated April 18, 2003 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2.2)
- *10.23.3 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gregory M. Rueger dated April 18, 2003 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2.4)
- *10.23.4 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated April 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.2.5)
- *10.24 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)
- *10.25 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)
- *10.26 PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)

- *10.27 PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (reflecting amendments adopted by the PG&E Corporation Board of Directors on June 16, 2004 set forth in resolutions filed as Exhibit 10.3 to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004)
- *10.28 Resolution of the PG&E Corporation Board of Directors dated June 16, 2004, adopting director compensation arrangement (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12609 and File No. 12348), Exhibit 10.1)
- *10.29 Resolution of the Pacific Gas and Electric Company Board of Directors dated June 16, 2004, adopting director compensation arrangement (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12609 and File No. 12348), Exhibit 10.2)
- *10.30 Form of Restricted Stock Award Agreement for 2003 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.46)
- *10.31 Form of Restricted Stock Award Agreement for 2004 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.37)
- *10.32 Form of Restricted Stock Agreement for 2005 grants under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.3)
- *10.33 Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.1)
- *10.34 Form of Performance Share Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.2)
- *10.35 Form of Performance Share Award Agreement granted under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.38)
- *10.36 PG&E Corporation Executive Stock Ownership Program Guidelines dated as of February 19, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609))
- *10.37 PG&E Corporation Officer Severance Policy, as amended effective as of January 1, 2005
- *10.38 PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)

*10.39	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005
*10.40	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996
*10.41	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995
11	Computation of Earnings Per Common Share
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
13	The following portions of the 2004 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations," financial statements of PG&E Corporation entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)," "Management's Report on Internal Control Over Financial Reporting," "Report of Independent Registered Public Accounting Firm," "Report of Independent Registered Public Accounting Firm," "Responsibility for Consolidated Financial Statements"
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
24.1	Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K
24.2	Powers of Attorney
31.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002

* Management contract or compensatory agreement.

** Pursuant to Item 601(b) (32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2004 to be signed on their behalf by the undersigned, thereunto duly authorized, in the City and County of San Francisco, on the 18th day of February, 2005.

By PG&E CORPORATION (Registrant) /s/ BRUCE R. WORTHINGTON (Bruce R. Worthington, Attorney-in-Fact)	By PACIFIC GAS AND ELECTRIC COMPANY (Registrant) /s/ BRUCE R. WORTHINGTON (Bruce R. Worthington, Attorney-in-Fact)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.

Signature	Title	Date
A. Principal Executive Officers		
*PETER A. DARBEE	Chief Executive Officer, and President (PG&E Corporation)	February 18, 2005
*GORDON R. SMITH	President and Chief Executive Officer (Pacific Gas and Electric Company)	February 18, 2005
B. Principal Financial Officers		
*CHRISTOPHER P. JOHNS	Senior Vice President, Chief Financial Officer and Controller (PG&E Corporation)	February 18, 2005
*KENT M. HARVEY	Senior Vice President, Chief Financial Officer, and Treasurer (Pacific Gas and Electric Company)	February 18, 2005
C. Principal Accounting Officers		
*CHRISTOPHER P. JOHNS	Senior Vice President, Chief Financial Officer, and Controller (PG&E Corporation)	February 18, 2005
*DINYAR B. MISTRY	Vice President-Controller (Pacific Gas and Electric Company)	February 18, 2005
D. Directors		
*DAVID R. ANDREWS		
*LESLIE S. BILLER		
*DAVID A. COULTER		
*C. LEE COX		
*PETER A. DARBEE		
*ROBERT D. GLYNN, JR.		
*DAVID M. LAWRENCE, M.D.		
*MARY S. METZ		
*BARBARA L. RAMBO		
*GORDON R. SMITH		
(Director of Pacific Gas and Electric Company only)		
*BARRY LAWSON WILLIAMS	Directors of PG&E Corporation and Pacific Gas and Electric Company, except as noted	February 18, 2005

*By /s/ BRUCE R. WORTHINGTON

 (Bruce R. Worthington, Attorney-in-Fact)

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2004 and 2003, and for each of the three years in the period ended December 31, 2004, management's assessment of the effectiveness of the Company's and the Utility's internal control over financial reporting as of December 31, 2004, and the effectiveness of the Company's and the Utility's internal control over financial reporting as of December 31, 2004, and have issued our reports thereon dated February 16, 2005 (which report expresses an unqualified opinion and includes an explanatory paragraph relating to accounting changes); such consolidated financial statements and reports are included in your 2004 Annual Report to Shareholders of the Company and the Utility and are incorporated herein by reference. Our audits also included the consolidated financial statement schedules of the Company and the Utility listed in Item 15 (a) 2. These consolidated financial statement schedules are the responsibility of the Company's and the Utility's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

San Francisco, California
February 16, 2005

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF PARENT

CONDENSED BALANCE SHEETS
(in millions)

		Balance at December 31,	
		2004	2003
ASSETS			
Cash and cash equivalents		\$ 183	\$ 673
Advances in affiliates		22	398
Other current assets		3	9
Total current assets		208	1,080
Equipment		15	20
Accumulated depreciation		(13)	(15)
Net equipment		2	5
Restricted cash		—	361
Investments in subsidiaries		8,848	4,810
Other investments		31	24
Deferred income taxes		104	478
Other		14	32
Total Assets		\$ 9,207	\$ 6,790
LIABILITIES AND SHAREHOLDERS' EQUITY			
Current Liabilities			
Accounts payable—related parties		\$ 3	\$ 2
Accounts payable—other		15	28
Income taxes payable		83	258
Other		53	158
Total current liabilities		154	446
Noncurrent Liabilities:			
Long-term debt		280	883
Net investment in NEGT		—	1,216
Other		140	30
Total noncurrent liabilities		420	2,129
Preferred stock		—	—
Common Shareholders' Equity			
Common stock		6,518	6,468
Common stock held by subsidiary		(718)	(690)
Unearned compensation		(26)	(20)
Accumulated earnings (deficit)		2,863	(1,458)
Accumulated other comprehensive loss		(4)	(85)
Total common shareholders' equity		8,633	4,215
Total Liabilities and Shareholders' Equity		\$ 9,207	\$ 6,790

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF PARENT (Continued)

CONDENSED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2004, 2003, and 2002
(in millions, except per share amounts)

	2004	2003	2002
Administrative service revenue	\$ 85	\$ 101	\$ 96
Equity in earnings of subsidiaries	3,959	917	1,842
Operating expenses	(110)	(133)	(141)
Interest income	15	20	30
Interest expense	(132)	(200)	(253)
Other income (expense)	(91)	2	81
Income before income taxes	3,726	707	1,655
Less: Income tax benefit	(94)	(84)	(68)
Income from continuing operations	3,820	791	1,723
Gain on disposal of NEG	684	—	—
Discontinued operations	—	(365)	(2,536)
Cumulative effect of changes in accounting principles	—	(6)	(61)
Net income (loss) before intercompany eliminations	\$ 4,504	\$ 420	\$ (874)
Weighted average common shares outstanding	\$ 398	\$ 385	\$ 371
Earnings (loss) per common share, basic ⁽¹⁾	\$ 10.80	\$ 1.04	\$ (2.30)
Earnings (loss) per common share, diluted ⁽¹⁾	\$ 10.57	\$ 1.02	\$ (2.27)

SCHEDULE I—CONDENSED FINANCIAL INFORMATION OF PARENT (Continued)

CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2004, 2003, and 2002
(in millions)

	2004	2003	2002
Cash Flows from Operating Activities:			
Net income (loss)	\$ 4,504	\$ 420	\$ (874)
Gain on disposal of NEGT (net of \$30 million payment to NEGT)	(684)	—	—
Loss from discontinued operations	—	365	2,536
Cumulative effect of changes in accounting principles	—	6	61
Net income from continuing operations	3,820	791	1,723
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Equity in earnings of subsidiaries	(3,959)	(917)	(1,842)
Restricted cash	361	—	—
Deferred taxes	27	265	(660)
NEGT settlement payment	(30)	—	—
Other—net	160	391	458
Net cash provided (used) by operating activities	379	530	(321)
Cash Flows From Investing Activities:			
Capital expenditures	—	—	(1)
Investment in subsidiaries	(28)	—	—
Net cash used by investing activities	(28)	—	(1)
Cash Flows From Financing Activities ⁽²⁾ :			
Common stock issued	162	166	217
Common stock repurchased	(350)	—	—
Long-term debt issued	—	581	847
Long-term debt redeemed	(652)	(787)	(908)
Other—net	(1)	1	—
Net cash provided (used) by financing activities	(841)	(39)	156
Net change in cash and cash equivalents	(490)	491	(166)
Cash and cash equivalents at January 1	673	182	348
Cash and cash equivalents at December 31	183	673	182

(1) PG&E Corporation adopted the consensus reached by Emerging Issues Task Force, or EITF, in EITF issue No. 03-06, "Participating Securities and the Two-Class Method under FASB Statement No. 128," or EITF 03-06, as ratified by the Financial Accounting Standards Board on March 31, 2004.

PG&E Corporation currently has outstanding \$280 million principal amount of convertible subordinated 9.50% notes due 2010, or Convertible Notes, that are entitled to receive (non-cumulative) dividend payments without exercising the conversion option. These Convertible Notes, which were issued in June 2002, meet the criteria of a participating security in the calculation of earnings per share using the "two-class" method.

Accordingly, the basic and diluted earnings per share calculations for each of the years in the three year period ended December 31, 2004 reflect the allocation of earnings between PG&E Corporation common stock and the participating security.

(2) PG&E Corporation did not receive any cash dividends during 2004, 2003 and 2002

PG&E CORPORATION

SCHEDULE II—CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2004, 2003 and 2002

Description	Balance at Beginning of Period	Additions		Deductions ⁽³⁾	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts		
			(in millions)		
Valuation and qualifying accounts deducted from assets:					
2004:					
Allowance for uncollectible accounts ⁽¹⁾⁽²⁾	\$ 68	\$ 85	\$ —	\$ 60	\$ 93
2003:					
Allowance for uncollectible accounts ⁽¹⁾⁽²⁾	\$ 59	\$ 42	\$ —	\$ 33	\$ 68
2002:					
Allowance for uncollectible accounts ⁽¹⁾⁽²⁾	\$ 48	\$ 36	\$ (2)	\$ 23	\$ 59

⁽¹⁾ Allowance for uncollectible accounts is deducted from "Accounts receivable Customers, net."

⁽²⁾ Allowance for uncollectible accounts does not include NEGT.

⁽³⁾ Deductions consist principally of write-offs, net of collections of receivables previously written off.

PACIFIC GAS AND ELECTRIC COMPANY

SCHEDULE II—CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2004, 2003 and 2002

Description	Balance at Beginning of Period	Additions		Deductions ⁽²⁾	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts		
			(in millions)		
Valuation and qualifying accounts deducted from assets:					
2004:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 68	\$ 85	\$ —	\$ 60	\$ 93
2003:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 59	\$ 42	\$ —	\$ 33	\$ 68
2002:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 48	\$ 36	\$ (2)	\$ 23	\$ 59

⁽¹⁾ Allowance for uncollectible accounts is deducted from "Accounts receivable Customers, net."

⁽²⁾ Deductions consist principally of write-offs, net of collections of receivables previously written off.

EXHIBIT INDEX

Exhibit Number	Exhibit Description
2.1	Order of the U.S. Bankruptcy Court for the Northern District of California dated December 22, 2003, Confirming Plan of Reorganization of Pacific Gas and Electric Company, including Plan of Reorganization, dated July 31, 2003 as modified by modifications dated November 6, 2003 and December 19, 2003 (Exhibit B to Confirmation Order and Exhibits B and C to the Plan of Reorganization omitted) (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.1)
2.2	Order of the U.S. Bankruptcy Court for the Northern District of California dated February 27, 2004 Approving Technical Corrections to Plan of Reorganization of Pacific Gas and Electric Company and Supplementing Confirmation Order to Incorporate such Corrections (incorporated by reference to Pacific Gas and Electric Company's Registration Statement on Form S-3 No. 333-109994, Exhibit 2.2)
3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1)
3.2	Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2)
3.3	Bylaws of PG&E Corporation amended as of January 1, 2005
3.4	Bylaws of PG&E Corporation amended as of April 20, 2005
3.5	Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-2348), Exhibit 3)
3.6	Bylaws of Pacific Gas and Electric Company amended as of January 1, 2005
3.7	Bylaws of Pacific Gas and Electric Company amended as of April 20, 2005
4.1	Indenture of Mortgage, dated as of March 11, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4.1)
4.2	First Supplemental Indenture, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4.2)
4.3	Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed April 12, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4)
4.4	Escrow Deposit and Disbursement Agreement, dated as of March 23, 2004, among Pacific Gas and Electric Company and BNY Western Trust Company as escrow agent and trustee (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4.3)
4.5	Calculation Agency Agreement, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 4.4)

- 4.6 Indenture related to PG&E Corporation's 7.5% Convertible Subordinated Notes due June 2007, dated as of June 25, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.1).
 - 4.7 Supplemental Indenture related to PG&E Corporation's 9.50% Convertible Subordinated Notes due June 2010, dated as of October 18, 2002, between PG&E Corporation and U.S. Bank, N.A., as Trustee (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1)
 - 4.8 Warrant Agreement, dated as of June 25, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Form 8-K filed June 26, 2002 (File No. 1-12609), Exhibit 99.9).
 - 4.9 Warrant Agreement, dated as of October 18, 2002, by and among PG&E Corporation, LB I Group Inc., and each other entity named on the signature pages thereto (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.2)
 - 10.1 Credit Agreement dated as of March 5, 2004, among Pacific Gas and Electric Company, as borrower, the Several Lenders from time to time parties thereto, Citicorp North America, Inc., as Administrative Agent, Banc One Capital Markets, Inc., as Syndication Agent, and Lehman Commercial Paper Inc., Credit Suisse First Boston, acting through its Cayman Islands Branch, and UBS Securities LLC, as Co- Documentation Agents (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 10, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 99)
 - 10.2 Credit Agreement, dated as of December 10, 2004, among PG&E Corporation, BNP Paribas, as administrative agent and a lender, Deutsche Bank Securities, as syndication agent, ABN Amro Bank, N.V., Goldman Sachs Credit Partners L.P., and Union Bank of California, N.A., as documentation agents and lenders, and the following other lenders: Barclays Bank PLC, Citicorp USA, Inc., Deutsche Bank AG New York Branch, JP Morgan Chase Bank, N.A., Lehman Brothers Bank, FSB, Morgan Stanley Bank, Royal Bank of Canada, The Bank of Nova Scotia, and The Bank of New York (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed December 15, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 99.)
 - 10.3 Master Confirmation dated December 15, 2004, for accelerated share repurchase arrangements between PG&E Corporation and Goldman, Sachs & Co.
 - 10.4 Settlement Agreement among California Public Utilities Commission, Pacific Gas and Electric Company and PG&E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K filed December 22, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 99)
 - 10.5 Firm Transportation Service Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated October 26, 1993, Rate Schedule FTS-1, and general terms and conditions (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.4)
 - 10.6 Operating Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated July 9, 1996 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.5)
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- 10.7 PG&E Trans-User Agreement between Pacific Gas and Electric Company and PG&E Gas Transmission, Northwest Corporation dated November 15, 1999 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2003) (File No. 1-12609 and File No. 1-2348), Exhibit 10.6)
 - 10.8 Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, initially effective March 31, 1998, as amended to date (CAISO, FERC Electric Tariff No. 7)
 - 10.9 Operating Agreement, as amended on November 12, 2004, effective as of December 22, 2004, between the State of California Department of Water Resources and Pacific Gas and Electric Company
 - *10.10 PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004
 - *10.11 PG&E Corporation Supplemental Retirement Savings Plan effective as of January 1, 2005
 - *10.12 Description of Compensation Arrangement between PG&E Corporation and Peter Darbee (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.3)
 - *10.13 Letter regarding Compensation Arrangement between PG&E Corporation and Peter A. Darbee effective June 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.4)
 - *10.14 Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated November 4, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.6)
 - *10.15 Letter Regarding Relocation Arrangement Between PG&E Corporation and Thomas B. King dated March 16, 2000 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 10)
 - *10.16 Letter regarding Compensation Arrangement between PG&E Corporation and Thomas B. King dated June 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.3)
 - *10.17 PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005
 - *10.18 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2005
 - *10.19 Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.24)
 - *10.20 Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended effective as of December 31, 2004, and frozen as of January 1, 2005
 - *10.21 Supplemental Executive Retirement Plan of PG&E Corporation effective January 1, 2005
 - *10.22.1 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Robert D. Glynn, Jr. dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.1)
 - *10.22.2 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated December 20, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.37.2)
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- *10.22.3 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gregory M. Rueger dated December 20, 2002 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2002 (File No. 1-12609 and File No. 1-2348), Exhibit 10.37.3)
 - *10.22.4 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gordon R. Smith dated December 20, 2002 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2002 (File No. 1-12609 and File No. 1-2348), Exhibit 10.37.4)
 - *10.22.5 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and James K. Randolph dated December 20, 2002 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2002 (File No. 1-12609 and File No. 1-2348), Exhibit 10.37.5)
 - *10.23.1 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Robert D. Glynn, Jr. dated April 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.2.1)
 - *10.23.2 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gordon R. Smith dated April 18, 2003 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2.2)
 - *10.23.3 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Gregory M. Rueger dated April 18, 2003 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2.4)
 - *10.23.4 Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Bruce R. Worthington dated April 18, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609), Exhibit 10.2.5)
 - *10.24 Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1989 (File No. 1-2348), Exhibit 10.16)
 - *10.25 Postretirement Life Insurance Plan of the Pacific Gas and Electric Company (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for fiscal year 1991 (File No. 1-2348), Exhibit 10.16)
 - *10.26 PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
 - *10.27 PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (reflecting amendments adopted by the PG&E Corporation Board of Directors on June 16, 2004 set forth in resolutions filed as Exhibit 10.3 to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004)
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*10.28	Resolution of the PG&E Corporation Board of Directors dated June 16, 2004, adopting director compensation arrangement (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12609 and File No. 12348), Exhibit 10.1)
*10.29	Resolution of the Pacific Gas and Electric Company Board of Directors dated June 16, 2004, adopting director compensation arrangement (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12609 and File No. 12348), Exhibit 10.2)
*10.30	Form of Restricted Stock Award Agreement for 2003 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.46)
*10.31	Form of Restricted Stock Award Agreement for 2004 grants made under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.37)
*10.32	Form of Restricted Stock Agreement for 2005 grants under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.3)
*10.33	Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.1)
*10.34	Form of Performance Share Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed January 6, 2005 (File No. 12609 and File No. 1-2348), Exhibit 99.2)
*10.35	Form of Performance Share Award Agreement granted under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2003 (File No. 1-12609), Exhibit 10.38)
*10.36	PG&E Corporation Executive Stock Ownership Program Guidelines dated as of February 19, 2003 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609))
*10.37	PG&E Corporation Officer Severance Policy, as amended effective as of January 1, 2005
*10.38	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
*10.39	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998, as updated effective January 1, 2005
*10.40	Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996
*10.41	Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995
11	Computation of Earnings Per Common Share
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company

12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
13	The following portions of the 2004 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company are included: "Selected Financial Data," "Management's Discussion and Analysis of Financial Condition and Results of Operations," financial statements of PG&E Corporation entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Shareholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)," "Management's Report on Internal Control Over Financial Reporting," "Report of Independent Registered Public Accounting Firm," "Report of Independent Registered Public Accounting Firm," "Responsibility for Consolidated Financial Statements"
21	Subsidiaries of the Registrant
23	Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP)
24.1	Resolutions of the Boards of Directors of PG&E Corporation and Pacific Gas and Electric Company authorizing the execution of the Form 10-K
24.2	Powers of Attorney
31.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002

* Management contract or compensatory agreement.

** Pursuant to Item 601(b) (32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.

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Exhibit 3.3

**Bylaws
of
PG&E Corporation
*amended as of January 1, 2005***

**Article I.
SHAREHOLDERS.**

1. **Place of Meeting** . All meetings of the shareholders shall be held at the office of the Corporation in the City and County of San Francisco, State of California, or at such other place, within or without the State of California, as may be designated by the Board of Directors.

2. **Annual Meetings** . The annual meeting of shareholders shall be held each year on a date and at a time designated by the Board of Directors.

Written notice of the annual meeting shall be given not less than ten (or, if sent by third-class mail, thirty) nor more than sixty days prior to the date of the meeting to each shareholder entitled to vote thereat. The notice shall state the place, day, and hour of such meeting, and those matters which the Board, at the time of mailing, intends to present for action by the shareholders.

Notice of any meeting of the shareholders shall be given by mail or telegraphic or other written communication, postage prepaid, to each holder of record of the stock entitled to vote thereat, at his address, as it appears on the books of the Corporation.

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation. To be timely, the shareholder's written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year's annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder's written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder's written notice to be timely must be so received not later than the close of business on the tenth day following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder's written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder's written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, if the shareholder's written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to

the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section.

3. **Special Meetings** . Special meetings of the shareholders shall be called by the Corporate Secretary or an Assistant Corporate Secretary at any time on order of the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, or the President. Special meetings of the shareholders shall also be called by the Corporate Secretary or an Assistant Corporate Secretary upon the written request of holders of shares entitled to cast not less than ten percent of the votes at the meeting. Such request shall state the purposes of the meeting, and shall be delivered to the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President, or the Corporate Secretary.

A special meeting so requested shall be held on the date requested, but not less than thirty-five nor more than sixty days after the date of the original request. Written notice of each special meeting of shareholders, stating the place, day, and hour of such meeting and the business proposed to be transacted thereat, shall be given in the manner stipulated in Article I, Section 2, Paragraph 3 of these Bylaws within twenty days after receipt of the written request.

4. **Voting at Meetings** . At any meeting of the shareholders, each holder of record of stock shall be entitled to vote in person or by proxy. The authority of proxies must be evidenced by a written document signed by the shareholder and must be delivered to the Corporate Secretary of the Corporation prior to the commencement of the meeting.

5. **Shareholder Action by Written Consent.** Subject to Section 603 of the California Corporations Code, any action which, under any provision of the California Corporations Code, may be taken at any annual or special meeting of shareholders may be taken without a meeting and without prior notice if a consent in writing, setting forth the action so taken, shall be signed by the holders of outstanding shares having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted.

Any party seeking to solicit written consent from shareholders to take corporate action must deliver a notice to the Corporate Secretary of the Corporation which requests the Board of Directors to set a record date for determining shareholders entitled to give such consent. Such written request must set forth as to each matter the party proposes for shareholder action by written consents (a) a brief description of the matter and (b) the class and number of shares of the Corporation that are beneficially owned by the requesting party. Within ten days of receiving the request in the proper form, the Board shall set a record date for the taking of such action by written consent in accordance with California Corporations Code Section 701 and Article IV, Section 1 of these Bylaws. If the Board fails to set a record date within such ten-day period, the record date for determining shareholders entitled to give the written consent for the matters specified in the notice shall be the day on which the first written consent is given in accordance with California Corporations Code Section 701.

Each written consent delivered to the Corporation must set forth (a) the action sought to be taken, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, (d) the name and address of the proxyholder authorized by the shareholder to give such written consent, if applicable, and (d) any material interest of the shareholder or proxyholder in the action sought to be taken.

Consents to corporate action shall be valid for a maximum of sixty days after the date of the earliest dated consent delivered to the Corporation. Consents may be revoked by written notice (i) to the Corporation, (ii) to the shareholder or shareholders soliciting consents or soliciting revocations in

opposition to action by consent proposed by the Corporation (the "Soliciting Shareholders"), or (iii) to a proxy solicitor or other agent designated by the Corporation or the Soliciting Shareholders.

Within three business days after receipt of the earliest dated consent solicited by the Soliciting Shareholders and delivered to the Corporation in the manner provided in California Corporations Code Section 603 or the determination by the Board of Directors of the Corporation that the Corporation should seek corporate action by written consent, as the case may be, the Corporate Secretary shall engage nationally recognized independent inspectors of elections for the purpose of performing a ministerial review of the validity of the consents and revocations. The cost of retaining inspectors of election shall be borne by the Corporation.

Consents and revocations shall be delivered to the inspectors upon receipt by the Corporation, the Soliciting Shareholders or their proxy solicitors, or other designated agents. As soon as consents and revocations are received, the inspectors shall review the consents and revocations and shall maintain a count of the number of valid and unrevoked consents. The inspectors shall keep such count confidential and shall not reveal the count to the Corporation, the Soliciting Shareholder or their representatives, or any other entity. As soon as practicable after the earlier of (i) sixty days after the date of the earliest dated consent delivered to the Corporation in the manner provided in California Corporations Code Section 603, or (ii) a written request therefor by the Corporation or the Soliciting Shareholders (whichever is soliciting consents), notice of which request shall be given to the party opposing the solicitation of consents, if any, which request shall state that the Corporation or Soliciting Shareholders, as the case may be, have a good faith belief that the requisite number of valid and unrevoked consents to authorize or take the action specified in the consents has been received in accordance with these Bylaws, the inspectors shall issue a preliminary report to the Corporation and the Soliciting Shareholders stating: (a) the number of valid consents, (b) the number of valid revocations, (c) the number of valid and unrevoked consents, (d) the number of invalid consents, (e) the number of invalid revocations, and (f) whether, based on their preliminary count, the requisite number of valid and unrevoked consents has been obtained to authorize or take the action specified in the consents.

Unless the Corporation and the Soliciting Shareholders shall agree to a shorter or longer period, the Corporation and the Soliciting Shareholders shall have forty-eight hours to review the consents and revocations and to advise the inspectors and the opposing party in writing as to whether they intend to challenge the preliminary report of the inspectors. If no written notice of an intention to challenge the preliminary report is received within forty-eight hours after the inspectors' issuance of the preliminary report, the inspectors shall issue to the Corporation and the Soliciting Shareholders their final report containing the information from the inspectors' determination with respect to whether the requisite number of valid and unrevoked consents was obtained to authorize and take the action specified in the consents. If the Corporation or the Soliciting Shareholders issue written notice of an intention to challenge the inspectors' preliminary report within forty-eight hours after the issuance of that report, a challenge session shall be scheduled by the inspectors as promptly as practicable. A transcript of the challenge session shall be recorded by a certified court reporter. Following completion of the challenge session, the inspectors shall as promptly as practicable issue their final report to the Soliciting Shareholders and the Corporation, which report shall contain the information included in the preliminary report, plus all changes in the vote totals as a result of the challenge and a certification of whether the requisite number of valid and unrevoked consents was obtained to authorize or take the action specified in the consents. A copy of the final report of the inspectors shall be included in the book in which the proceedings of meetings of shareholders are recorded.

Unless the consent of all shareholders entitled to vote have been solicited in writing, the Corporation shall give prompt notice to the shareholders in accordance with California Corporations Code Section 603 of the results of any consent solicitation or the taking of the corporate action without a meeting and by less than unanimous written consent.

Article II. DIRECTORS.

1. **Number** . As stated in paragraph I of Article Third of this Corporation's Articles of Incorporation, the Board of Directors of this Corporation shall consist of such number of directors, not less than seven (7) nor more than thirteen (13). The exact number of directors shall be ten (10) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

2. **Powers** . The Board of Directors shall exercise all the powers of the Corporation except those which are by law, or by the Articles of Incorporation of this Corporation, or by the Bylaws conferred upon or reserved to the shareholders.

3. **Committees** . The Board of Directors may, by resolution adopted by a majority of the authorized number of directors, designate and appoint one or more committees as the Board deems appropriate, each consisting of two or more directors, to serve at the pleasure of the Board; provided, however, that, as required by this Corporation's Articles of Incorporation, the members of the Executive Committee (should the Board of Directors designate an Executive Committee) must be appointed by the affirmative vote of two-thirds of the authorized number of directors. Any such committee, including the Executive Committee, shall have the authority to act in the manner and to the extent provided in the resolution of the Board of Directors designating such committee and may have all the authority of the Board of Directors, except with respect to the matters set forth in California Corporations Code Section 311.

4. **Time and Place of Directors' Meetings** . Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, or the President of the Corporation and contained in the notice of any such meeting. Notice of meetings shall be delivered personally or sent by mail or telegram at least seven days in advance.

5. **Special Meetings** . The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate messages, including facsimile, electronic mail, or other such means) to each Director at least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.

6. **Quorum** . A quorum for the transaction of business at any meeting of the Board of Directors or any committee thereof shall consist of one-third of the authorized number of directors or committee members, or two, whichever is larger.

7. **Action by Consent** . Any action required or permitted to be taken by the Board of Directors may be taken without a meeting if all Directors individually or collectively consent in writing to such action. Such written consent or consents shall be filed with the minutes of the proceedings of the Board of Directors.

8. **Meetings by Conference Telephone** . Any meeting, regular or special, of the Board of Directors or of any committee of the Board of Directors, may be held by conference telephone or similar communication equipment, provided that all Directors participating in the meeting can hear one another.

Article III. OFFICERS.

1. **Officers** . The officers of the Corporation shall be a Chairman of the Board, a Vice Chairman of the Board, a Chairman of the Executive Committee (whenever the Board of Directors in its discretion fills these offices), a President, a Chief Financial Officer, a General Counsel, one or more Vice Presidents, a Corporate Secretary and one or more Assistant Corporate Secretaries, a Treasurer and one or more Assistant Treasurers, and a Controller, all of whom shall be elected by the Board of Directors. The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, and the President shall be members of the Board of Directors.

2. **Chairman of the Board** . The Chairman of the Board, if that office be filled, shall preside at all meetings of the shareholders and of the Directors, and shall preside at all meetings of the Executive Committee in the absence of the Chairman of that Committee. The Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. The Chairman of the Board shall have such duties and responsibilities as may be prescribed by the Board of Directors or the Bylaws. The Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character, and, in the absence or disability of the President, shall exercise the President's duties and responsibilities.

3. **Vice Chairman of the Board** . The Vice Chairman of the Board, if that office be filled, shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The Vice Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. In the absence of the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Board of Directors and of the shareholders; and, in the absence of the Chairman of the Executive Committee and the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

4. **Chairman of the Executive Committee** . The Chairman of the Executive Committee, if that office be filled, shall preside at all meetings of the Executive Committee. The Chairman of the Executive Committee shall aid and assist the other officers in the performance of their duties and shall have such other duties as may be prescribed by the Board of Directors or the Bylaws.

5. **President** . The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The President shall be the chief executive officer of the Corporation if so designated by the Board of Directors. If there be no Chairman of the Board, the President shall also exercise the duties and responsibilities of that office. The President shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

6. **Chief Financial Officer** . The Chief Financial Officer shall be responsible for the overall management of the financial affairs of the Corporation. The Chief Financial Officer shall render a statement of the Corporation's financial condition and an account of all transactions whenever requested by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, or the President.

The Chief Financial Officer shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

7. **General Counsel** . The General Counsel shall be responsible for handling on behalf of the Corporation all proceedings and matters of a legal nature. The General Counsel shall render advice and legal counsel to the Board of Directors, officers, and employees of the Corporation, as necessary to

the proper conduct of the business. The General Counsel shall keep the management of the Corporation informed of all significant developments of a legal nature affecting the interests of the Corporation.

The General Counsel shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

8. **Vice Presidents** . Each Vice President, if those offices are filled, shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws. Each Vice President's authority to sign agreements and instruments on behalf of the Corporation shall be as prescribed by the Board of Directors. The Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, or the President may confer a special title upon any Vice President.

9. **Corporate Secretary** . The Corporate Secretary shall attend all meetings of the Board of Directors and the Executive Committee, and all meetings of the shareholders, and the Corporate Secretary shall record the minutes of all proceedings in books to be kept for that purpose. The Corporate Secretary shall be responsible for maintaining a proper share register and stock transfer books for all classes of shares issued by the Corporation. The Corporate Secretary shall give, or cause to be given, all notices required either by law or the Bylaws. The Corporate Secretary shall keep the seal of the Corporation in safe custody, and shall affix the seal of the Corporation to any instrument requiring it and shall attest the same by the Corporate Secretary's signature.

The Corporate Secretary shall have such other duties as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

The Assistant Corporate Secretaries shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Corporate Secretary. In the absence or disability of the Corporate Secretary, the Corporate Secretary's duties shall be performed by an Assistant Corporate Secretary.

10. **Treasurer** . The Treasurer shall have custody of all moneys and funds of the Corporation, and shall cause to be kept full and accurate records of receipts and disbursements of the Corporation. The Treasurer shall deposit all moneys and other valuables of the Corporation in the name and to the credit of the Corporation in such depositories as may be designated by the Board of Directors or any employee of the Corporation designated by the Board of Directors. The Treasurer shall disburse such funds of the Corporation as have been duly approved for disbursement.

The Treasurer shall perform such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, the Chief Financial Officer, or the Bylaws.

The Assistant Treasurers shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, the Chief Financial Officer, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

11. **Controller** . The Controller shall be responsible for maintaining the accounting records of the Corporation and for preparing necessary financial reports and statements, and the Controller shall properly account for all moneys and obligations due the Corporation and all properties, assets, and liabilities of the Corporation. The Controller shall render to the officers such periodic reports covering the result of operations of the Corporation as may be required by them or any one of them.

The Controller shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, the Chief

Financial Officer, or the Bylaws. The Controller shall be the principal accounting officer of the Corporation, unless another individual shall be so designated by the Board of Directors.

Article IV. MISCELLANEOUS.

1. **Record Date** . The Board of Directors may fix a time in the future as a record date for the determination of the shareholders entitled to notice of and to vote at any meeting of shareholders, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise rights in respect to any change, conversion, or exchange of shares. The record date so fixed shall be not more than sixty nor less than ten days prior to the date of such meeting nor more than sixty days prior to any other action for the purposes for which it is so fixed. When a record date is so fixed, only shareholders of record on that date are entitled to notice of and to vote at the meeting, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise the rights, as the case may be.

2. **Transfers of Stock** . Upon surrender to the Corporate Secretary or Transfer Agent of the Corporation of a certificate for shares duly endorsed or accompanied by proper evidence of succession, assignment, or authority to transfer, and payment of transfer taxes, the Corporation shall issue a new certificate to the person entitled thereto, cancel the old certificate, and record the transaction upon its books. Subject to the foregoing, the Board of Directors shall have power and authority to make such rules and regulations as it shall deem necessary or appropriate concerning the issue, transfer, and registration of certificates for shares of stock of the Corporation, and to appoint and remove Transfer Agents and Registrars of transfers.

3. **Lost Certificates** . Any person claiming a certificate of stock to be lost, stolen, mislaid, or destroyed shall make an affidavit or affirmation of that fact and verify the same in such manner as the Board of Directors may require, and shall, if the Board of Directors so requires, give the Corporation, its Transfer Agents, Registrars, and/or other agents a bond of indemnity in form approved by counsel, and in amount and with such sureties as may be satisfactory to the Corporate Secretary of the Corporation, before a new certificate may be issued of the same tenor and for the same number of shares as the one alleged to have been lost, stolen, mislaid, or destroyed.

Article V. AMENDMENTS.

1. **Amendment by Shareholders** . Except as otherwise provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by the affirmative vote of a majority of the outstanding shares entitled to vote at any regular or special meeting of the shareholders.

2. **Amendment by Directors** . To the extent provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by resolution adopted by a majority of the members of the Board of Directors.

Exhibit 3.3

Bylaws of PG&E Corporation amended as of January 1, 2005

Article I. SHAREHOLDERS.

Article II. DIRECTORS.

Article III. OFFICERS.

Article IV. MISCELLANEOUS.

Article V. AMENDMENTS.

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Exhibit 3.4

**Bylaws
of
PG&E Corporation
amended as of April 20, 2005**

**Article I.
SHAREHOLDERS.**

1. **Place of Meeting** . All meetings of the shareholders shall be held at the office of the Corporation in the City and County of San Francisco, State of California, or at such other place, within or without the State of California, as may be designated by the Board of Directors.

2. **Annual Meetings** . The annual meeting of shareholders shall be held each year on a date and at a time designated by the Board of Directors.

Written notice of the annual meeting shall be given not less than ten (or, if sent by third-class mail, thirty) nor more than sixty days prior to the date of the meeting to each shareholder entitled to vote thereat. The notice shall state the place, day, and hour of such meeting, and those matters which the Board, at the time of mailing, intends to present for action by the shareholders.

Notice of any meeting of the shareholders shall be given by mail or telegraphic or other written communication, postage prepaid, to each holder of record of the stock entitled to vote thereat, at his address, as it appears on the books of the Corporation.

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation. To be timely, the shareholder's written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year's annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder's written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder's written notice to be timely must be so received not later than the close of business on the tenth day following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder's written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder's written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, if the shareholder's written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to

the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section.

3. **Special Meetings** . Special meetings of the shareholders shall be called by the Corporate Secretary or an Assistant Corporate Secretary at any time on order of the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, or the President. Special meetings of the shareholders shall also be called by the Corporate Secretary or an Assistant Corporate Secretary upon the written request of holders of shares entitled to cast not less than ten percent of the votes at the meeting. Such request shall state the purposes of the meeting, and shall be delivered to the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President, or the Corporate Secretary.

A special meeting so requested shall be held on the date requested, but not less than thirty-five nor more than sixty days after the date of the original request. Written notice of each special meeting of shareholders, stating the place, day, and hour of such meeting and the business proposed to be transacted thereat, shall be given in the manner stipulated in Article I, Section 2, Paragraph 3 of these Bylaws within twenty days after receipt of the written request.

4. **Voting at Meetings** . At any meeting of the shareholders, each holder of record of stock shall be entitled to vote in person or by proxy. The authority of proxies must be evidenced by a written document signed by the shareholder and must be delivered to the Corporate Secretary of the Corporation prior to the commencement of the meeting.

5. **Shareholder Action by Written Consent** . Subject to Section 603 of the California Corporations Code, any action which, under any provision of the California Corporations Code, may be taken at any annual or special meeting of shareholders may be taken without a meeting and without prior notice if a consent in writing, setting forth the action so taken, shall be signed by the holders of outstanding shares having not less than the minimum number of votes that would be necessary to authorize or take such action at a meeting at which all shares entitled to vote thereon were present and voted.

Any party seeking to solicit written consent from shareholders to take corporate action must deliver a notice to the Corporate Secretary of the Corporation which requests the Board of Directors to set a record date for determining shareholders entitled to give such consent. Such written request must set forth as to each matter the party proposes for shareholder action by written consents (a) a brief description of the matter and (b) the class and number of shares of the Corporation that are beneficially owned by the requesting party. Within ten days of receiving the request in the proper form, the Board shall set a record date for the taking of such action by written consent in accordance with California Corporations Code Section 701 and Article IV, Section 1 of these Bylaws. If the Board fails to set a record date within such ten-day period, the record date for determining shareholders entitled to give the written consent for the matters specified in the notice shall be the day on which the first written consent is given in accordance with California Corporations Code Section 701.

Each written consent delivered to the Corporation must set forth (a) the action sought to be taken, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, (d) the name and address of the proxyholder authorized by the shareholder to give such written consent, if applicable, and (d) any material interest of the shareholder or proxyholder in the action sought to be taken.

Consents to corporate action shall be valid for a maximum of sixty days after the date of the earliest dated consent delivered to the Corporation. Consents may be revoked by written notice (i) to the Corporation, (ii) to the shareholder or shareholders soliciting consents or soliciting revocations in

opposition to action by consent proposed by the Corporation (the "Soliciting Shareholders"), or (iii) to a proxy solicitor or other agent designated by the Corporation or the Soliciting Shareholders.

Within three business days after receipt of the earliest dated consent solicited by the Soliciting Shareholders and delivered to the Corporation in the manner provided in California Corporations Code Section 603 or the determination by the Board of Directors of the Corporation that the Corporation should seek corporate action by written consent, as the case may be, the Corporate Secretary shall engage nationally recognized independent inspectors of elections for the purpose of performing a ministerial review of the validity of the consents and revocations. The cost of retaining inspectors of election shall be borne by the Corporation.

Consents and revocations shall be delivered to the inspectors upon receipt by the Corporation, the Soliciting Shareholders or their proxy solicitors, or other designated agents. As soon as consents and revocations are received, the inspectors shall review the consents and revocations and shall maintain a count of the number of valid and unrevoked consents. The inspectors shall keep such count confidential and shall not reveal the count to the Corporation, the Soliciting Shareholder or their representatives, or any other entity. As soon as practicable after the earlier of (i) sixty days after the date of the earliest dated consent delivered to the Corporation in the manner provided in California Corporations Code Section 603, or (ii) a written request therefor by the Corporation or the Soliciting Shareholders (whichever is soliciting consents), notice of which request shall be given to the party opposing the solicitation of consents, if any, which request shall state that the Corporation or Soliciting Shareholders, as the case may be, have a good faith belief that the requisite number of valid and unrevoked consents to authorize or take the action specified in the consents has been received in accordance with these Bylaws, the inspectors shall issue a preliminary report to the Corporation and the Soliciting Shareholders stating: (a) the number of valid consents, (b) the number of valid revocations, (c) the number of valid and unrevoked consents, (d) the number of invalid consents, (e) the number of invalid revocations, and (f) whether, based on their preliminary count, the requisite number of valid and unrevoked consents has been obtained to authorize or take the action specified in the consents.

Unless the Corporation and the Soliciting Shareholders shall agree to a shorter or longer period, the Corporation and the Soliciting Shareholders shall have forty-eight hours to review the consents and revocations and to advise the inspectors and the opposing party in writing as to whether they intend to challenge the preliminary report of the inspectors. If no written notice of an intention to challenge the preliminary report is received within forty-eight hours after the inspectors' issuance of the preliminary report, the inspectors shall issue to the Corporation and the Soliciting Shareholders their final report containing the information from the inspectors' determination with respect to whether the requisite number of valid and unrevoked consents was obtained to authorize and take the action specified in the consents. If the Corporation or the Soliciting Shareholders issue written notice of an intention to challenge the inspectors' preliminary report within forty-eight hours after the issuance of that report, a challenge session shall be scheduled by the inspectors as promptly as practicable. A transcript of the challenge session shall be recorded by a certified court reporter. Following completion of the challenge session, the inspectors shall as promptly as practicable issue their final report to the Soliciting Shareholders and the Corporation, which report shall contain the information included in the preliminary report, plus all changes in the vote totals as a result of the challenge and a certification of whether the requisite number of valid and unrevoked consents was obtained to authorize or take the action specified in the consents. A copy of the final report of the inspectors shall be included in the book in which the proceedings of meetings of shareholders are recorded.

Unless the consent of all shareholders entitled to vote have been solicited in writing, the Corporation shall give prompt notice to the shareholders in accordance with California Corporations Code Section 603 of the results of any consent solicitation or the taking of the corporate action without a meeting and by less than unanimous written consent.

Article II. DIRECTORS.

1. **Number** . As stated in paragraph I of Article Third of this Corporation's Articles of Incorporation, the Board of Directors of this Corporation shall consist of such number of directors, not less than seven (7) nor more than thirteen (13). The exact number of directors shall be nine (9) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

2. **Powers** . The Board of Directors shall exercise all the powers of the Corporation except those which are by law, or by the Articles of Incorporation of this Corporation, or by the Bylaws conferred upon or reserved to the shareholders.

3. **Committees** . The Board of Directors may, by resolution adopted by a majority of the authorized number of directors, designate and appoint one or more committees as the Board deems appropriate, each consisting of two or more directors, to serve at the pleasure of the Board; provided, however, that, as required by this Corporation's Articles of Incorporation, the members of the Executive Committee (should the Board of Directors designate an Executive Committee) must be appointed by the affirmative vote of two-thirds of the authorized number of directors. Any such committee, including the Executive Committee, shall have the authority to act in the manner and to the extent provided in the resolution of the Board of Directors designating such committee and may have all the authority of the Board of Directors, except with respect to the matters set forth in California Corporations Code Section 311.

4. **Time and Place of Directors' Meetings** . Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, or the President of the Corporation and contained in the notice of any such meeting. Notice of meetings shall be delivered personally or sent by mail or telegram at least seven days in advance.

5. **Special Meetings** . The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate messages, including facsimile, electronic mail, or other such means) to each Director at least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.

6. **Quorum** . A quorum for the transaction of business at any meeting of the Board of Directors or any committee thereof shall consist of one-third of the authorized number of directors or committee members, or two, whichever is larger.

7. **Action by Consent** . Any action required or permitted to be taken by the Board of Directors may be taken without a meeting if all Directors individually or collectively consent in writing to such action. Such written consent or consents shall be filed with the minutes of the proceedings of the Board of Directors.

8. **Meetings by Conference Telephone** . Any meeting, regular or special, of the Board of Directors or of any committee of the Board of Directors, may be held by conference telephone or similar communication equipment, provided that all Directors participating in the meeting can hear one another.

Article III. OFFICERS.

1. **Officers** . The officers of the Corporation shall be a Chairman of the Board, a Vice Chairman of the Board, a Chairman of the Executive Committee (whenever the Board of Directors in its discretion fills these offices), a President, a Chief Financial Officer, a General Counsel, one or more Vice Presidents, a Corporate Secretary and one or more Assistant Corporate Secretaries, a Treasurer and one or more Assistant Treasurers, and a Controller, all of whom shall be elected by the Board of Directors. The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, and the President shall be members of the Board of Directors.

2. **Chairman of the Board** . The Chairman of the Board, if that office be filled, shall preside at all meetings of the shareholders and of the Directors, and shall preside at all meetings of the Executive Committee in the absence of the Chairman of that Committee. The Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. The Chairman of the Board shall have such duties and responsibilities as may be prescribed by the Board of Directors or the Bylaws. The Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character, and, in the absence or disability of the President, shall exercise the President's duties and responsibilities.

3. **Vice Chairman of the Board** . The Vice Chairman of the Board, if that office be filled, shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The Vice Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. In the absence of the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Board of Directors and of the shareholders; and, in the absence of the Chairman of the Executive Committee and the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

4. **Chairman of the Executive Committee** . The Chairman of the Executive Committee, if that office be filled, shall preside at all meetings of the Executive Committee. The Chairman of the Executive Committee shall aid and assist the other officers in the performance of their duties and shall have such other duties as may be prescribed by the Board of Directors or the Bylaws.

5. **President** . The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The President shall be the chief executive officer of the Corporation if so designated by the Board of Directors. If there be no Chairman of the Board, the President shall also exercise the duties and responsibilities of that office. The President shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

6. **Chief Financial Officer** . The Chief Financial Officer shall be responsible for the overall management of the financial affairs of the Corporation. The Chief Financial Officer shall render a statement of the Corporation's financial condition and an account of all transactions whenever requested by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, or the President.

The Chief Financial Officer shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

7. **General Counsel** . The General Counsel shall be responsible for handling on behalf of the Corporation all proceedings and matters of a legal nature. The General Counsel shall render advice and legal counsel to the Board of Directors, officers, and employees of the Corporation, as necessary to

the proper conduct of the business. The General Counsel shall keep the management of the Corporation informed of all significant developments of a legal nature affecting the interests of the Corporation.

The General Counsel shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

8. **Vice Presidents** . Each Vice President, if those offices are filled, shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws. Each Vice President's authority to sign agreements and instruments on behalf of the Corporation shall be as prescribed by the Board of Directors. The Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, or the President may confer a special title upon any Vice President.

9. **Corporate Secretary** . The Corporate Secretary shall attend all meetings of the Board of Directors and the Executive Committee, and all meetings of the shareholders, and the Corporate Secretary shall record the minutes of all proceedings in books to be kept for that purpose. The Corporate Secretary shall be responsible for maintaining a proper share register and stock transfer books for all classes of shares issued by the Corporation. The Corporate Secretary shall give, or cause to be given, all notices required either by law or the Bylaws. The Corporate Secretary shall keep the seal of the Corporation in safe custody, and shall affix the seal of the Corporation to any instrument requiring it and shall attest the same by the Corporate Secretary's signature.

The Corporate Secretary shall have such other duties as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

The Assistant Corporate Secretaries shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Corporate Secretary. In the absence or disability of the Corporate Secretary, the Corporate Secretary's duties shall be performed by an Assistant Corporate Secretary.

10. **Treasurer** . The Treasurer shall have custody of all moneys and funds of the Corporation, and shall cause to be kept full and accurate records of receipts and disbursements of the Corporation. The Treasurer shall deposit all moneys and other valuables of the Corporation in the name and to the credit of the Corporation in such depositories as may be designated by the Board of Directors or any employee of the Corporation designated by the Board of Directors. The Treasurer shall disburse such funds of the Corporation as have been duly approved for disbursement.

The Treasurer shall perform such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, the Chief Financial Officer, or the Bylaws.

The Assistant Treasurers shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, the Chief Financial Officer, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

11. **Controller** . The Controller shall be responsible for maintaining the accounting records of the Corporation and for preparing necessary financial reports and statements, and the Controller shall properly account for all moneys and obligations due the Corporation and all properties, assets, and liabilities of the Corporation. The Controller shall render to the officers such periodic reports covering the result of operations of the Corporation as may be required by them or any one of them.

The Controller shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, the Chief

Financial Officer, or the Bylaws. The Controller shall be the principal accounting officer of the Corporation, unless another individual shall be so designated by the Board of Directors.

Article IV. MISCELLANEOUS.

1. **Record Date** . The Board of Directors may fix a time in the future as a record date for the determination of the shareholders entitled to notice of and to vote at any meeting of shareholders, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise rights in respect to any change, conversion, or exchange of shares. The record date so fixed shall be not more than sixty nor less than ten days prior to the date of such meeting nor more than sixty days prior to any other action for the purposes for which it is so fixed. When a record date is so fixed, only shareholders of record on that date are entitled to notice of and to vote at the meeting, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise the rights, as the case may be.

2. **Transfers of Stock** . Upon surrender to the Corporate Secretary or Transfer Agent of the Corporation of a certificate for shares duly endorsed or accompanied by proper evidence of succession, assignment, or authority to transfer, and payment of transfer taxes, the Corporation shall issue a new certificate to the person entitled thereto, cancel the old certificate, and record the transaction upon its books. Subject to the foregoing, the Board of Directors shall have power and authority to make such rules and regulations as it shall deem necessary or appropriate concerning the issue, transfer, and registration of certificates for shares of stock of the Corporation, and to appoint and remove Transfer Agents and Registrars of transfers.

3. **Lost Certificates** . Any person claiming a certificate of stock to be lost, stolen, mislaid, or destroyed shall make an affidavit or affirmation of that fact and verify the same in such manner as the Board of Directors may require, and shall, if the Board of Directors so requires, give the Corporation, its Transfer Agents, Registrars, and/or other agents a bond of indemnity in form approved by counsel, and in amount and with such sureties as may be satisfactory to the Corporate Secretary of the Corporation, before a new certificate may be issued of the same tenor and for the same number of shares as the one alleged to have been lost, stolen, mislaid, or destroyed.

Article V. AMENDMENTS.

1. **Amendment by Shareholders** . Except as otherwise provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by the affirmative vote of a majority of the outstanding shares entitled to vote at any regular or special meeting of the shareholders.

2. **Amendment by Directors** . To the extent provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by resolution adopted by a majority of the members of the Board of Directors.

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[Bylaws of PG&E Corporation amended as of April 20, 2005](#)

[Article I. SHAREHOLDERS.](#)

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Exhibit 3.6

**Bylaws
of
Pacific Gas and Electric Company
*amended as of January 1, 2005***

**Article I.
SHAREHOLDERS.**

1. **Place of Meeting.** All meetings of the shareholders shall be held at the office of the Corporation in the City and County of San Francisco, State of California, or at such other place, within or without the State of California, as may be designated by the Board of Directors.

2. **Annual Meetings.** The annual meeting of shareholders shall be held each year on a date and at a time designated by the Board of Directors.

Written notice of the annual meeting shall be given not less than ten (or, if sent by third-class mail, thirty) nor more than sixty days prior to the date of the meeting to each shareholder entitled to vote thereat. The notice shall state the place, day, and hour of such meeting, and those matters which the Board, at the time of mailing, intends to present for action by the shareholders.

Notice of any meeting of the shareholders shall be given by mail or telegraphic or other written communication, postage prepaid, to each holder of record of the stock entitled to vote thereat, at his address, as it appears on the books of the Corporation.

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation. To be timely, the shareholder's written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year's annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder's written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder's written notice to be timely must be so received not later than the close of business on the tenth day following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder's written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder's written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, if the shareholder's written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to

the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section.

3. **Special Meetings.** Special meetings of the shareholders shall be called by the Corporate Secretary or an Assistant Corporate Secretary at any time on order of the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, or the President. Special meetings of the shareholders shall also be called by the Corporate Secretary or an Assistant Corporate Secretary upon the written request of holders of shares entitled to cast not less than ten percent of the votes at the meeting. Such request shall state the purposes of the meeting, and shall be delivered to the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President or the Corporate Secretary.

A special meeting so requested shall be held on the date requested, but not less than thirty-five nor more than sixty days after the date of the original request. Written notice of each special meeting of shareholders, stating the place, day, and hour of such meeting and the business proposed to be transacted thereat, shall be given in the manner stipulated in Article I, Section 2, Paragraph 3 of these Bylaws within twenty days after receipt of the written request.

4. **Voting at Meetings.** At any meeting of the shareholders, each holder of record of stock shall be entitled to vote in person or by proxy. The authority of proxies must be evidenced by a written document signed by the shareholder and must be delivered to the Corporate Secretary of the Corporation prior to the commencement of the meeting.

5. **No Cumulative Voting.** No shareholder of the Corporation shall be entitled to cumulate his or her voting power.

Article II. DIRECTORS.

1. **Number.** The Board of Directors of this Corporation shall consist of such number of directors, not less than nine (9) nor more than seventeen (17). The exact number of directors shall be eleven (11) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

2. **Powers.** The Board of Directors shall exercise all the powers of the Corporation except those which are by law, or by the Articles of Incorporation of this Corporation, or by the Bylaws conferred upon or reserved to the shareholders.

3. **Committees.** The Board of Directors may, by resolution adopted by a majority of the authorized number of directors, designate and appoint one or more committees as the Board deems appropriate, each consisting of two or more directors, to serve at the pleasure of the Board; provided, however, that, as required by this Corporation's Articles of Incorporation, the members of the Executive Committee (should the Board of Directors designate an Executive Committee) must be appointed by the affirmative vote of two-thirds of the authorized number of directors. Any such committee, including the Executive Committee, shall have the authority to act in the manner and to the extent provided in the resolution of the Board of Directors designating such committee and may have all the authority of the Board of Directors, except with respect to the matters set forth in California Corporations Code Section 311.

4. **Time and Place of Directors' Meetings.** Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, or the President of the Corporation and contained in the notice of any such meeting. Notice of meetings shall be delivered personally or sent by mail or telegram at least seven days in advance.

5. **Special Meetings.** The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate messages, including facsimile, electronic mail, or other such means) to each Director at least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.

6. **Quorum.** A quorum for the transaction of business at any meeting of the Board of Directors or any committee thereof shall consist of one-third of the authorized number of directors or committee members, or two, whichever is larger.

7. **Action by Consent.** Any action required or permitted to be taken by the Board of Directors may be taken without a meeting if all Directors individually or collectively consent in writing to such action. Such written consent or consents shall be filed with the minutes of the proceedings of the Board of Directors.

8. **Meetings by Conference Telephone.** Any meeting, regular or special, of the Board of Directors or of any committee of the Board of Directors, may be held by conference telephone or similar communication equipment, provided that all Directors participating in the meeting can hear one another.

Article III. OFFICERS.

1. **Officers.** The officers of the Corporation shall be a Chairman of the Board, a Vice Chairman of the Board, a Chairman of the Executive Committee (whenever the Board of Directors in its discretion fills these offices), a President, one or more Vice Presidents, a Corporate Secretary and one or more Assistant Corporate Secretaries, a Treasurer and one or more Assistant Treasurers, a General Counsel, a General Attorney (whenever the Board of Directors in its discretion fills this office), and a Controller, all of whom shall be elected by the Board of Directors. The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, and the President shall be members of the Board of Directors.

2. **Chairman of the Board.** The Chairman of the Board, if that office be filled, shall preside at all meetings of the shareholders, of the Directors, and of the Executive Committee in the absence of the Chairman of that Committee. The Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. The Chairman of the Board shall have such duties and responsibilities as may be prescribed by the Board of Directors or the Bylaws. The Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character, and in the absence or disability of the President, shall exercise his duties and responsibilities.

3. **Vice Chairman of the Board.** The Vice Chairman of the Board, if that office be filled, shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The Vice Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. In the absence of the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Board of Directors and of the shareholders; and, in the absence of the Chairman of the Executive Committee and the Chairman of the Board, The Vice Chairman of the Board shall preside at all meetings of the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

4. **Chairman of the Executive Committee.** The Chairman of the Executive Committee, if that office be filled, shall preside at all meetings of the Executive Committee. The Chairman of the Executive Committee shall aid and assist the other officers in the performance of their duties and shall have such other duties as may be prescribed by the Board of Directors or the Bylaws.

5. **President.** The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The President shall be the chief executive officer of the Corporation if so designated by the Board of Directors. If there be no Chairman of the Board, the President shall also exercise the duties and responsibilities of that office. The President shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

6. **Vice Presidents.** Each Vice President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws. Each Vice President's authority to sign agreements and instruments on behalf of the Corporation shall be as prescribed by the Board of Directors. The Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, or the President may confer a special title upon any Vice President.

7. **Corporate Secretary.** The Corporate Secretary shall attend all meetings of the Board of Directors and the Executive Committee, and all meetings of the shareholders, and the Corporate Secretary shall record the minutes of all proceedings in books to be kept for that purpose. The Corporate Secretary shall be responsible for maintaining a proper share register and stock transfer books for all classes of shares issued by the Corporation. The Corporate Secretary shall give, or cause to be given, all notices required either by law or the Bylaws. The Corporate Secretary shall keep the seal of the Corporation in safe custody, and shall affix the seal of the Corporation to any instrument requiring it and shall attest the same by the Corporate Secretary's signature.

The Corporate Secretary shall have such other duties as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

The Assistant Corporate Secretaries shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Corporate Secretary. In the absence or disability of the Corporate Secretary, the Corporate Secretary's duties shall be performed by an Assistant Corporate Secretary.

8. **Treasurer.** The Treasurer shall have custody of all moneys and funds of the Corporation, and shall cause to be kept full and accurate records of receipts and disbursements of the Corporation. The Treasurer shall deposit all moneys and other valuables of the Corporation in the name and to the credit of the Corporation in such depositories as may be designated by the Board of Directors or any employee of the Corporation designated by the Board of Directors. The Treasurer shall disburse such funds of the Corporation as have been duly approved for disbursement.

The Treasurer shall perform such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

The Assistant Treasurer shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

9. **General Counsel.** The General Counsel shall be responsible for handling on behalf of the Corporation all proceedings and matters of a legal nature. The General Counsel shall render advice and legal counsel to the Board of Directors, officers, and employees of the Corporation, as necessary to

the proper conduct of the business. The General Counsel shall keep the management of the Corporation informed of all significant developments of a legal nature affecting the interests of the Corporation.

The General Counsel shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

10. **Controller.** The Controller shall be responsible for maintaining the accounting records of the Corporation and for preparing necessary financial reports and statements, and the Controller shall properly account for all moneys and obligations due the Corporation and all properties, assets, and liabilities of the Corporation. The Controller shall render to the officers such periodic reports covering the result of operations of the Corporation as may be required by them or any one of them.

The Controller shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws. The Controller shall be the principal accounting officer of the Corporation, unless another individual shall be so designated by the Board of Directors.

Article IV. MISCELLANEOUS.

1. **Record Date.** The Board of Directors may fix a time in the future as a record date for the determination of the shareholders entitled to notice of and to vote at any meeting of shareholders, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise rights in respect to any change, conversion, or exchange of shares. The record date so fixed shall be not more than sixty nor less than ten days prior to the date of such meeting nor more than sixty days prior to any other action for the purposes for which it is so fixed. When a record date is so fixed, only shareholders of record on that date are entitled to notice of and to vote at the meeting, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise the rights, as the case may be.

2. **Transfers of Stock.** Upon surrender to the Corporate Secretary or Transfer Agent of the Corporation of a certificate for shares duly endorsed or accompanied by proper evidence of succession, assignment, or authority to transfer, and payment of transfer taxes, the Corporation shall issue a new certificate to the person entitled thereto, cancel the old certificate, and record the transaction upon its books. Subject to the foregoing, the Board of Directors shall have power and authority to make such rules and regulations as it shall deem necessary or appropriate concerning the issue, transfer, and registration of certificates for shares of stock of the Corporation, and to appoint and remove Transfer Agents and Registrars of transfers.

3. **Lost Certificates.** Any person claiming a certificate of stock to be lost, stolen, mislaid, or destroyed shall make an affidavit or affirmation of that fact and verify the same in such manner as the Board of Directors may require, and shall, if the Board of Directors so requires, give the Corporation, its Transfer Agents, Registrars, and/or other agents a bond of indemnity in form approved by counsel, and in amount and with such sureties as may be satisfactory to the Corporate Secretary of the Corporation, before a new certificate may be issued of the same tenor and for the same number of shares as the one alleged to have been lost, stolen, mislaid, or destroyed.

Article V. AMENDMENTS.

1. **Amendment by Shareholders.** Except as otherwise provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by the affirmative vote of a majority of the outstanding shares entitled to vote at any regular or special meeting of the shareholders.

2. **Amendment by Directors.** To the extent provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by resolution adopted by a majority of the members of the Board of Directors.

Exhibit 3.6

Bylaws of Pacific Gas and Electric Company amended as of January 1, 2005

Article I. SHAREHOLDERS.

Article II. DIRECTORS.

Article III. OFFICERS.

Article IV. MISCELLANEOUS.

Article V. AMENDMENTS.

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Exhibit 3.7

**Bylaws
of
Pacific Gas and Electric Company
amended as of April 20, 2005**

**Article I.
SHAREHOLDERS.**

1. **Place of Meeting.** All meetings of the shareholders shall be held at the office of the Corporation in the City and County of San Francisco, State of California, or at such other place, within or without the State of California, as may be designated by the Board of Directors.

2. **Annual Meetings.** The annual meeting of shareholders shall be held each year on a date and at a time designated by the Board of Directors.

Written notice of the annual meeting shall be given not less than ten (or, if sent by third-class mail, thirty) nor more than sixty days prior to the date of the meeting to each shareholder entitled to vote thereat. The notice shall state the place, day, and hour of such meeting, and those matters which the Board, at the time of mailing, intends to present for action by the shareholders.

Notice of any meeting of the shareholders shall be given by mail or telegraphic or other written communication, postage prepaid, to each holder of record of the stock entitled to vote thereat, at his address, as it appears on the books of the Corporation.

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation. To be timely, the shareholder's written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year's annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder's written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder's written notice to be timely must be so received not later than the close of business on the tenth day following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder's written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder's written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, if the shareholder's written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to

the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section.

3. **Special Meetings.** Special meetings of the shareholders shall be called by the Corporate Secretary or an Assistant Corporate Secretary at any time on order of the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, or the President. Special meetings of the shareholders shall also be called by the Corporate Secretary or an Assistant Corporate Secretary upon the written request of holders of shares entitled to cast not less than ten percent of the votes at the meeting. Such request shall state the purposes of the meeting, and shall be delivered to the Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President or the Corporate Secretary.

A special meeting so requested shall be held on the date requested, but not less than thirty-five nor more than sixty days after the date of the original request. Written notice of each special meeting of shareholders, stating the place, day, and hour of such meeting and the business proposed to be transacted thereat, shall be given in the manner stipulated in Article I, Section 2, Paragraph 3 of these Bylaws within twenty days after receipt of the written request.

4. **Voting at Meetings.** At any meeting of the shareholders, each holder of record of stock shall be entitled to vote in person or by proxy. The authority of proxies must be evidenced by a written document signed by the shareholder and must be delivered to the Corporate Secretary of the Corporation prior to the commencement of the meeting.

5. **No Cumulative Voting.** No shareholder of the Corporation shall be entitled to cumulate his or her voting power.

Article II. DIRECTORS.

1. **Number.** The Board of Directors of this Corporation shall consist of such number of directors, not less than nine (9) nor more than seventeen (17). The exact number of directors shall be ten (10) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.

2. **Powers.** The Board of Directors shall exercise all the powers of the Corporation except those which are by law, or by the Articles of Incorporation of this Corporation, or by the Bylaws conferred upon or reserved to the shareholders.

3. **Committees.** The Board of Directors may, by resolution adopted by a majority of the authorized number of directors, designate and appoint one or more committees as the Board deems appropriate, each consisting of two or more directors, to serve at the pleasure of the Board; provided, however, that, as required by this Corporation's Articles of Incorporation, the members of the Executive Committee (should the Board of Directors designate an Executive Committee) must be appointed by the affirmative vote of two-thirds of the authorized number of directors. Any such committee, including the Executive Committee, shall have the authority to act in the manner and to the extent provided in the resolution of the Board of Directors designating such committee and may have all the authority of the Board of Directors, except with respect to the matters set forth in California Corporations Code Section 311.

4. **Time and Place of Directors' Meetings.** Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, or the President of the Corporation and contained in the notice of any such meeting. Notice of meetings shall be delivered personally or sent by mail or telegram at least seven days in advance.

5. **Special Meetings.** The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate messages, including facsimile, electronic mail, or other such means) to each Director at least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.

6. **Quorum.** A quorum for the transaction of business at any meeting of the Board of Directors or any committee thereof shall consist of one-third of the authorized number of directors or committee members, or two, whichever is larger.

7. **Action by Consent.** Any action required or permitted to be taken by the Board of Directors may be taken without a meeting if all Directors individually or collectively consent in writing to such action. Such written consent or consents shall be filed with the minutes of the proceedings of the Board of Directors.

8. **Meetings by Conference Telephone.** Any meeting, regular or special, of the Board of Directors or of any committee of the Board of Directors, may be held by conference telephone or similar communication equipment, provided that all Directors participating in the meeting can hear one another.

Article III. OFFICERS.

1. **Officers.** The officers of the Corporation shall be a Chairman of the Board, a Vice Chairman of the Board, a Chairman of the Executive Committee (whenever the Board of Directors in its discretion fills these offices), a President, one or more Vice Presidents, a Corporate Secretary and one or more Assistant Corporate Secretaries, a Treasurer and one or more Assistant Treasurers, a General Counsel, a General Attorney (whenever the Board of Directors in its discretion fills this office), and a Controller, all of whom shall be elected by the Board of Directors. The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, and the President shall be members of the Board of Directors.

2. **Chairman of the Board.** The Chairman of the Board, if that office be filled, shall preside at all meetings of the shareholders, of the Directors, and of the Executive Committee in the absence of the Chairman of that Committee. The Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. The Chairman of the Board shall have such duties and responsibilities as may be prescribed by the Board of Directors or the Bylaws. The Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character, and in the absence or disability of the President, shall exercise his duties and responsibilities.

3. **Vice Chairman of the Board.** The Vice Chairman of the Board, if that office be filled, shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The Vice Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. In the absence of the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Board of Directors and of the shareholders; and, in the absence of the Chairman of the Executive Committee and the Chairman of the Board, The Vice Chairman of the Board shall preside at all meetings of the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

4. **Chairman of the Executive Committee.** The Chairman of the Executive Committee, if that office be filled, shall preside at all meetings of the Executive Committee. The Chairman of the Executive Committee shall aid and assist the other officers in the performance of their duties and shall have such other duties as may be prescribed by the Board of Directors or the Bylaws.

5. **President.** The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. The President shall be the chief executive officer of the Corporation if so designated by the Board of Directors. If there be no Chairman of the Board, the President shall also exercise the duties and responsibilities of that office. The President shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

6. **Vice Presidents.** Each Vice President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws. Each Vice President's authority to sign agreements and instruments on behalf of the Corporation shall be as prescribed by the Board of Directors. The Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, or the President may confer a special title upon any Vice President.

7. **Corporate Secretary.** The Corporate Secretary shall attend all meetings of the Board of Directors and the Executive Committee, and all meetings of the shareholders, and the Corporate Secretary shall record the minutes of all proceedings in books to be kept for that purpose. The Corporate Secretary shall be responsible for maintaining a proper share register and stock transfer books for all classes of shares issued by the Corporation. The Corporate Secretary shall give, or cause to be given, all notices required either by law or the Bylaws. The Corporate Secretary shall keep the seal of the Corporation in safe custody, and shall affix the seal of the Corporation to any instrument requiring it and shall attest the same by the Corporate Secretary's signature.

The Corporate Secretary shall have such other duties as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

The Assistant Corporate Secretaries shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Corporate Secretary. In the absence or disability of the Corporate Secretary, the Corporate Secretary's duties shall be performed by an Assistant Corporate Secretary.

8. **Treasurer.** The Treasurer shall have custody of all moneys and funds of the Corporation, and shall cause to be kept full and accurate records of receipts and disbursements of the Corporation. The Treasurer shall deposit all moneys and other valuables of the Corporation in the name and to the credit of the Corporation in such depositories as may be designated by the Board of Directors or any employee of the Corporation designated by the Board of Directors. The Treasurer shall disburse such funds of the Corporation as have been duly approved for disbursement.

The Treasurer shall perform such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

The Assistant Treasurer shall perform such duties as may be assigned from time to time by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

9. **General Counsel.** The General Counsel shall be responsible for handling on behalf of the Corporation all proceedings and matters of a legal nature. The General Counsel shall render advice and legal counsel to the Board of Directors, officers, and employees of the Corporation, as necessary to

the proper conduct of the business. The General Counsel shall keep the management of the Corporation informed of all significant developments of a legal nature affecting the interests of the Corporation.

The General Counsel shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws.

10. **Controller.** The Controller shall be responsible for maintaining the accounting records of the Corporation and for preparing necessary financial reports and statements, and the Controller shall properly account for all moneys and obligations due the Corporation and all properties, assets, and liabilities of the Corporation. The Controller shall render to the officers such periodic reports covering the result of operations of the Corporation as may be required by them or any one of them.

The Controller shall have such other duties as may from time to time be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws. The Controller shall be the principal accounting officer of the Corporation, unless another individual shall be so designated by the Board of Directors.

Article IV. MISCELLANEOUS.

1. **Record Date.** The Board of Directors may fix a time in the future as a record date for the determination of the shareholders entitled to notice of and to vote at any meeting of shareholders, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise rights in respect to any change, conversion, or exchange of shares. The record date so fixed shall be not more than sixty nor less than ten days prior to the date of such meeting nor more than sixty days prior to any other action for the purposes for which it is so fixed. When a record date is so fixed, only shareholders of record on that date are entitled to notice of and to vote at the meeting, or entitled to receive any dividend or distribution, or allotment of rights, or to exercise the rights, as the case may be.

2. **Transfers of Stock.** Upon surrender to the Corporate Secretary or Transfer Agent of the Corporation of a certificate for shares duly endorsed or accompanied by proper evidence of succession, assignment, or authority to transfer, and payment of transfer taxes, the Corporation shall issue a new certificate to the person entitled thereto, cancel the old certificate, and record the transaction upon its books. Subject to the foregoing, the Board of Directors shall have power and authority to make such rules and regulations as it shall deem necessary or appropriate concerning the issue, transfer, and registration of certificates for shares of stock of the Corporation, and to appoint and remove Transfer Agents and Registrars of transfers.

3. **Lost Certificates.** Any person claiming a certificate of stock to be lost, stolen, mislaid, or destroyed shall make an affidavit or affirmation of that fact and verify the same in such manner as the Board of Directors may require, and shall, if the Board of Directors so requires, give the Corporation, its Transfer Agents, Registrars, and/or other agents a bond of indemnity in form approved by counsel, and in amount and with such sureties as may be satisfactory to the Corporate Secretary of the Corporation, before a new certificate may be issued of the same tenor and for the same number of shares as the one alleged to have been lost, stolen, mislaid, or destroyed.

Article V. AMENDMENTS.

1. **Amendment by Shareholders.** Except as otherwise provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by the affirmative vote of a majority of the outstanding shares entitled to vote at any regular or special meeting of the shareholders.

2. **Amendment by Directors.** To the extent provided by law, these Bylaws, or any of them, may be amended or repealed or new Bylaws adopted by resolution adopted by a majority of the members of the Board of Directors.

[QuickLinks](#)

[Exhibit 3.7](#)

[Bylaws of Pacific Gas and Electric Company amended as of April 20, 2005](#)

[Article I. SHAREHOLDERS.](#)

[Article II. DIRECTORS.](#)

[Article III. OFFICERS.](#)

[Article IV. MISCELLANEOUS.](#)

[Article V. AMENDMENTS.](#)

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Exhibit 10.3

EXECUTION COPY

GOLDMAN SACHS & CO. -- 85 BROAD STREET -- NEW YORK, NEW YORK 10004 -- TEL: 212-902-1000

Opening Transaction

To: PG&E Corporation
One Market Spear Tower
Suite 2400
San Francisco, CA 94105

From: Goldman, Sachs & Co.

Subject: Accelerated Share Repurchase Transaction—VWAP Pricing
(Non-Collared)

Ref. No: EN41JA000000000

Date: December 15, 2004

This master confirmation ("Master Confirmation") dated as of December 15, 2004, is intended to supplement the terms and provisions of certain Transactions (each, a "Transaction") entered into from time to time between Goldman, Sachs & Co. ("GS&Co.") and PG&E Corporation ("Counterparty"). This Master Confirmation, taken alone, is neither a commitment by either party to enter into any Transaction nor evidence of a Transaction. The terms of any particular Transaction shall be set forth in a Supplemental Confirmation in the form of Annex A, which references this Master Confirmation, in which event the terms and provisions of this Master Confirmation shall be deemed to be incorporated into and made a part of each such Supplemental Confirmation. This Master Confirmation and each Supplemental Confirmation together shall constitute a "Confirmation" as referred to in the Agreement specified below.

The definitions and provisions contained in the 2002 ISDA Equity Derivatives Definitions (the "Equity Definitions"), as published by the International Swaps and Derivatives Association, Inc., are incorporated into this Master Confirmation. This Master Confirmation and each Supplemental Confirmation evidences a complete binding agreement between the Counterparty and GS&Co. as to the terms of each Transaction to which this Master Confirmation and the related Supplemental Confirmation relates.

This Master Confirmation and each Supplemental Confirmation, together with all other documents referring to the 1992 ISDA Master Agreement (Multicurrency-Cross Border) (the "ISDA Form" or the "Agreement"), confirming Transactions entered into between GS&Co. and Counterparty, shall supplement, form a part of, and be subject to the ISDA Form as if GS&Co. and Counterparty had executed the Agreement (but without any Schedule) except that the following elections and modifications shall be made: (i) the election of Loss and Second Method, New York law (without regard to conflicts of law principles) as the governing law and US Dollars ("USD") as the Termination Currency, (ii) the election that subparagraph (ii) of Section 2(c) will not apply to Transactions, (iii) the replacement of the word "third" in the last line of Section 5(a)(i) with the word "first", (iv) the election that the "Cross Default" provisions of Section 5(a)(vi) shall apply to Counterparty, with a "Threshold Amount" of USD 75 million) and (v) the replacement of clause (1) in Section 6(d)(i) with the clause "(1) showing in reasonable detail such calculations and specifying any amount payable under Section 6(e) (including, without limitation, providing all relevant quotations and assumptions and specifying the methodologies used in sufficient detail so as to enable the other party to replicate the calculation)". Further, for purposes of determining whether an Event of Default pursuant to Section 5(a)(vi) of the Agreement has occurred, notwithstanding anything to the contrary stated in that

provision, clause (1) of Section 5(a)(vi) will apply only to Specified Indebtedness that is actually declared to be due and payable before it would otherwise be due and payable under the relevant agreement or instrument, and not to Specified Indebtedness that is merely "capable at such time of being declared" so due and payable.

All provisions contained in the Agreement shall govern this Master Confirmation and the related Supplemental Confirmation relating to a Transaction except as expressly modified herein or in the related Supplemental Confirmation. With respect to any relevant Transaction, the Agreement, this Master Confirmation and the related Supplemental Confirmation shall represent the entire agreement and understanding of the parties with respect to the subject matter and terms of such Transaction and shall supersede all prior or contemporaneous written or oral communications with respect thereto.

If, in relation to any Transaction to which this Master Confirmation and related Supplemental Confirmation relate, there is any inconsistency between the Agreement, this Master Confirmation, any Supplemental Confirmation and the Equity Definitions that are incorporated into this Master Confirmation or any Supplemental Confirmation, the following will prevail for purposes of such Transaction in the order of precedence indicated: (i) such Supplemental Confirmation; (ii) this Master Confirmation; (iii) the Agreement; and (iv) the Equity Definitions.

1. Each Transaction constitutes a Share Forward Transaction for the purposes of the Equity Definitions. Set forth below are the terms and conditions which, together with the terms and conditions set forth in each Supplemental Confirmation (in respect of each relevant Transaction), shall govern each such Transaction.

General Terms:

Trade Date:	For each Transaction, as set forth in the Supplemental Confirmation.
Seller:	Counterparty
Buyer:	GS&Co.
Shares:	Common Stock of PG&E Corp. (Ticker: PCG)
Number of Shares:	For each Transaction, as set forth in the Supplemental Confirmation.
Forward Price:	For each Transaction, as set forth in the Supplemental Confirmation.
Prepayment:	Not Applicable
Variable Obligation:	Not Applicable
Exchange:	New York Stock Exchange
Related Exchange(s):	All Exchanges
Market Disruption Event:	The definition of "Market Disruption Event" in Section 6.3(a) of the Equity Definitions is hereby amended by inserting the words "at any time on any Scheduled Trading Day during the Valuation Period or" after the word "material," in the third line thereof.

Valuation:

Valuation Period:	Each Scheduled Trading Day during the period commencing on and including the Valuation Period Start Date to and including the Valuation Date (but excluding any day(s) on which the Valuation Period is suspended in accordance with Section 5 herein and including any day(s) by which the Valuation Period is extended pursuant to the provision below). Notwithstanding anything to the contrary in the Equity Definitions, to the extent that any Scheduled Trading Day in the Valuation Period is a Disrupted Day, the Valuation Date shall be postponed and the Calculation Agent in its sole discretion shall extend the Valuation Period and make adjustments to the weighting of each Relevant Price for purposes of determining the Settlement Price, with such adjustments based on, among other factors, the duration of any Market Disruption Event and the volume, historical trading patterns and price of the Shares. To the extent that there are 9 consecutive Disrupted Days during the Valuation Period, then notwithstanding the occurrence of a Disrupted Day, the Calculation Agent shall have the option in its sole discretion to either determine the Relevant Price using its good faith estimate of the value for the Share on such 9th consecutive day or elect to further extend the Valuation Period as it deems necessary.
Valuation Period Start Date:	For each Transaction, as set forth in the Supplemental Confirmation.
Valuation Date:	For each Transaction, as set forth in the Supplemental Confirmation (as the same may be postponed in accordance with the provisions of "Valuation Period" and Section 5 herein).
Settlement Terms:	
Settlement Currency:	USD (all amounts shall be converted to the Settlement Currency in good faith and in a commercially reasonable manner by the Calculation Agent).
Settlement Method Election:	Applicable; provided that (a) Section 7.1 of the Equity Definitions is hereby amended by deleting the word "Physical" in the sixth line thereof and replacing it with the words "Net Share" and deleting the word "Physical" in the last line thereof and replacing it with word "Cash" and (b) in the event that GS&Co. would deliver to the Counterparty an amount of Shares under Net Share Settlement, Cash Settlement shall be applicable in lieu of Net Share Settlement.
Electing Party:	Counterparty

Settlement Method Election Date:	10 Scheduled Trading Days prior to the originally scheduled Valuation Date.
Default Settlement Method:	Cash Settlement
Forward Cash Settlement Amount:	An amount in the Settlement Currency equal to the product of (a) the Number of Shares multiplied by (b) an amount equal to (i) the Settlement Price minus (ii) the Forward Price.
Settlement Price:	The arithmetic mean of the Relevant Prices of the Shares for each Exchange Business Day in the Valuation Period.
Relevant Price:	The New York 10b-18 Volume Weighted Average Price per share of the Shares for the regular trading session (including any extensions thereof) of the Exchange on the related Exchange Business Day (without regard to pre-open or after hours trading outside of such regular trading session) as published by Bloomberg at 4:15 p.m. New York time on such date.
Cash Settlement Payment Date:	3 Currency Business Days after the Valuation Date.
Counterparty's Contact Details for Purpose of Giving Notice:	To be provided by Counterparty
GS&Co.'s Contact Details for Purpose of Giving Notice:	Telephone No.: (212) 902-8996 Facsimile No.: (212) 902-0112 Attention: Equity Operations: Options and Derivatives With a copy to: Jim Ziperski Equity Capital Markets One New York Plaza New York, NY 10004 Telephone No.: (212) 902-8557 Facsimile No.: (212) 346-2126
Net Share Settlement:	
Net Share Settlement Procedures:	Net Share Settlement shall be made in accordance with the procedures attached hereto as Annex B.
Net Share Settlement Price:	The Net Share Settlement Price shall be the price per Share as of the Valuation Time on the Net Share Valuation Date as reported in the official real-time price dissemination mechanism for the Exchange. The Net Share Settlement Price shall be reduced by the per Share amount of the underwriting discount and/or commissions agreed to pursuant to the equity underwriting or agency agreement contemplated by the Net Share Settlement Procedures.

Valuation Time:	As provided in Section 6.1 of the Equity Definitions; provided that Section 6.1 of the Equity Definitions is hereby amended by inserting the words "Net Share," before the words "Valuation Date" in the first and third lines thereof.
Net Share Valuation Date:	The Exchange Business Day immediately following the Valuation Date.
Net Share Settlement Date:	The third Exchange Business Day immediately following the Valuation Date.
Reserved Shares:	For each Transaction, as set forth in the Supplemental Confirmation.
Fixed and Floating Amounts Payable:	
Floating Amount Payable by GS&Co.:	
Floating Amount Payment Date:	The Cash Settlement Payment Date
Floating Amount:	For each Transaction, an amount equal to the sum of the applicable Federal Funds Rate multiplied by (i) the Daily Notional Amount multiplied by (ii) 1/360 for each day from and including the Floating Amount Accrual Date to and including the Valuation Date.
Floating Amount Accrual Date:	Trade Date
Federal Funds Rate:	For any date of determination, the "Fed Funds Open Rate," which shall be the interest rate reported on Bloomberg under the symbol "FEDSOPEN <index>" on such date. For the avoidance of doubt, for any day which is not a Currency Business Day the "Federal Funds Open Rate" for the immediately preceding Currency Business Day shall apply.
Daily Notional Amount:	Commencing with the Floating Amount Accrual Date, for any date of determination, the Daily Notional Amount shall be an amount equal to the product of the Initial Notional Amount (as set forth in the Supplemental Confirmation) multiplied by a fraction with a numerator equal to the number of Scheduled Trading Days in the Valuation Period minus the number of Exchange Business Days in the Valuation Period that have elapsed (other than any days during which the Valuation Period is suspended pursuant to Section 5 herein) as of such date of determination and a denominator equal to the number of Scheduled Trading Days in the Valuation Period (such fraction, the "Remaining Percentage").

To the extent that the Valuation Period is extended pursuant to the terms of this Master Confirmation, the Calculation Agent shall adjust the Daily Notional Amount commencing with the first Exchange Business Day after such extension (the "Valuation Period Extension Date"). The notional amount deemed to be remaining at the end of the Exchange Business Day before the Valuation Period Extension Date (the "Remaining Notional Value") shall be the Initial Notional Value multiplied by the Remaining Percentage at the end of such day. Commencing with the Valuation Period Extension Date, for any date of determination, the Daily Notional Amount shall be equal to the product of the Remaining Notional Value multiplied by a fraction with (a) a numerator equal to (i) the number of Scheduled Trading Days remaining from and including the Valuation Period Extension Date to the Valuation Date after extension (the "Remaining Scheduled Trading Days") minus (ii) the number of Exchange Business Days in the Valuation Period after extension from and including the Valuation Period Extension Date that have elapsed (other than any days during which the Valuation Period after extension is suspended pursuant to Section 5 herein) as of such date of determination and (b) a denominator equal to the Remaining Scheduled Trading Days.

Fixed Amount Payable by Counterparty:

Fixed Amount Payment Date:

The Cash Settlement Payment Date

Fixed Amount:

For each Transaction, an amount equal to the sum of (I) the applicable Daily Additional Spread multiplied by (i) the Daily Notional Amount multiplied by (ii) 1/360 for each day from and including the Floating Amount Accrual Date to and including the Valuation Date plus (II) an amount equal to the sum of the applicable Fixed Rate multiplied by (i) the Notional Amount multiplied by (ii) 1/360 for each day from and including the Floating Amount Accrual Date to and including the Valuation Date.

Fixed Rate:

For each Transaction, as set forth in the Supplemental Confirmation.

Daily Additional Spread:

The Additional Spread shall be 25 basis points

Notional Amount:

For any date of determination, 105% of the Daily Notional Amount.

Settlement Terms for Fixed Amount:

Settlement Currency:

USD (all amounts shall be converted to the Settlement Currency in good faith and in a commercially reasonable manner by the Calculation Agent).

Settlement Method Election:	Applicable; provided that Section 7.1 of the Equity Definitions is hereby amended by deleting the word "Physical" in the sixth line thereof and replacing it with the words "Net Share" and deleting the word "Physical" in the last line thereof and replacing it with the word "Cash".
Electing Party:	Counterparty
Settlement Method Election Date:	10 Scheduled Trading Days prior to the originally scheduled Valuation Date.
Default Settlement Method:	Cash Settlement
Share Adjustments:	
Method of Adjustment:	Calculation Agent Adjustment
Extraordinary Events:	
Consequences of Merger Events:	Subject to Section 7(b) of the Master Confirmation:
(a) Share-for-Share:	Modified Calculation Agent Adjustment
(b) Share-for-Other:	Cancellation and Payment on that portion of the Other Consideration that consists of cash; Modified Calculation Agent Adjustment on the remainder of the Other Consideration.
(c) Share-for-Combined:	Component Adjustment
Determining Party:	GS&Co.
Tender Offer:	Applicable
Consequences of Tender Offers:	Subject to Section 7(b) of the Master Confirmation:
(a) Share-for-Share:	Modified Calculation Agent Adjustment
(b) Share-for-Other:	Cancellation and Payment on that portion of the Other Consideration that consists of cash; Modified Calculation Agent Adjustment on the remainder of the Other Consideration.
(c) Share-for-Combined:	Component Adjustment
Determining Party:	GS&Co.
Nationalization, Insolvency or Delisting:	Subject to Section 7(a) of this Master Confirmation, Negotiated Close-out; provided that in addition to the provisions of Section 12.6(a)(iii) of the Equity Definitions, it shall also constitute a Delisting if the Exchange is located in the United States and the Shares are not immediately re-listed, re-traded or re-quoted on any of the New York Stock Exchange, the American Stock Exchange or The NASDAQ National Market (or their respective successors); if the Shares are immediately re-listed, re-traded or re-quoted on any such exchange or quotation system, such exchange or quotation system shall be deemed to be the Exchange.

Additional Disruption Events:

(a)	Change in Law:	Applicable; provided that Section 12.9(a)(ii)(Y) of the Equity Definitions is hereby deleted.
(b)	Failure to Deliver:	Not Applicable
(c)	Insolvency Filing:	Applicable
(d)	Loss of Stock Borrow:	Applicable; provided that Loss of Stock Borrow shall not constitute an Additional Disruption Event so long as Counterparty agrees to pay the Hedging Party the amount by which the stock loan rate necessary to maintain a borrowing of Shares by GS&Co. ("Hedge Position") in connection with the Transaction exceeds the Maximum Stock Loan Rate.

	Maximum Stock Loan Rate	30 basis points

(e)	Hedging Disruption:	Not Applicable.
(f)	Increased Cost of Hedging:	Not Applicable.
(g)	Increased Cost of Stock Borrow:	Not Applicable.

	Hedging Party:	GS&Co.

	Determining Party:	GS&Co.

Non-Reliance:	Applicable

Agreements and Acknowledgements Regarding Hedging Activities:	Applicable

Additional Acknowledgements:	Applicable

Net Share Settlement following Extraordinary Event:

Counterparty shall have the right, in its sole discretion, to make any payment required to be made by it pursuant to Sections 12.7 or 12.9 of the Equity Definitions (except with respect to any portion of the consideration for the Shares consisting of cash in the event of a Merger Event or Tender Offer) following the occurrence of an Extraordinary Event by electing to Net Share Settle the Transactions under this Master Confirmation in accordance with the terms, and subject to the conditions, for Net Share Settlement herein by giving written notice to GS&Co. of such election on the day that the notice fixing the date that the Transactions are terminated or cancelled, as the case may be, (the "Cancellation Date") pursuant to the applicable provisions of Section 12 of the Equity Definitions is effective. If Counterparty elects Net Share Settlement: (a) the Net Share Valuation Date shall be the date specified in the notice fixing the date that the Transactions are terminated or cancelled, as the case may be; provided that the Net Share Valuation Date shall be either the Exchange Business Day that such notice is effective or the first Exchange Business Day immediately following the Exchange Business Day that such notice is effective, (b) the Net Share Settlement Date shall be deemed to be the Exchange Business Day immediately following the Cancellation Date and (c) all references to the Forward Cash Settlement Amount or the Fixed Amount, as the case may be, in Annex B hereto shall be deemed to be references to the Cancellation Amount. The definition of "Cancellation Amount" in Section 12.8 of the Equity Definitions is hereby amended by inserting the following paragraph: "(h) The Determining Party shall show the other party in reasonable detail its calculation of the Cancellation Amount, including without limitation providing all relevant quotations and assumptions and specifying the methodologies used in sufficient detail so as to enable the other party to replicate the calculation".

Net Share Settlement Upon Early Termination:

Counterparty shall have the right, in its sole discretion, to make any payment required to be made by it (the "Early Termination Amount") pursuant to Sections 6(d) and 6(e) of the Agreement following the occurrence of an Early Termination Date in respect of the Agreement by electing to Net Share Settle all the Transactions under this Master Confirmation in accordance with the terms, and subject to the conditions, for Net Share Settlement herein by giving written notice to GS&Co. of such election on the day that the notice fixing an Early Termination Date is effective. If Counterparty elects Net Share Settlement: (a) the Net Share Valuation Date shall be the date specified in the notice fixing an Early Termination Date; provided that the Net Share Valuation Date shall be either the Exchange Business Day that such notice is effective or the first Exchange Business Day immediately following the Exchange Business Day that such notice is effective, (b) the Net Share Settlement Date shall be deemed to be the Exchange Business Day immediately following the Early Termination Date (except for an Early Termination as a result of Section 7(d), in which event the Net Share Settlement Date shall be deemed to be the tenth Exchange Business Day following the Early Termination Date) and (c) all references to Forward Cash Settlement Amount or the Fixed Amount, as the case may be, in Annex B hereto shall be deemed references to the Early Termination Amount.

Transfer:

Notwithstanding anything to the contrary in the Agreement, GS&Co. may assign, transfer and set over all rights, title and interest, powers, privileges and remedies of GS&Co. under any Transaction, in whole or in part, to an affiliate of GS&Co. that is fully and unconditionally guaranteed by The Goldman Sachs Group, Inc. without the consent of Counterparty, provided that Counterparty is not required to make a payment to GS&Co. in respect of an Indemnifiable Tax as a result of such transfer.

GS&Co. Payment Instructions:

Chase Manhattan Bank New York
For A/C Goldman, Sachs & Co.
A/C # 930-1-011483
ABA: 021-000021

Counterparty Payment Instructions:

PG&E Corporation Master Account No. 099023
Mellon Trust of New England, N.A.
Boston, MA
ABA Routing No: 011001234

2. *Calculation Agent : GS&Co.*

3. *Representations, Warranties and Covenants of GS&Co. and Counterparty .*

(a) Each party represents and warrants that it (i) is an "eligible contract participant", as defined in the U.S. Commodity Exchange Act, as amended and (ii) is entering into each

Transaction hereunder as principal (and not as agent or in any other capacity, fiduciary or otherwise) and not for the benefit of any third party.

(b) Each party acknowledges that the offer and sale of each Share Forward Transaction to it is intended to be exempt from registration under the Securities Act of 1933, as amended (the "Securities Act"), by virtue of Section 4(2) thereof and the provisions of Regulation D promulgated thereunder ("Regulation D"); and this acknowledgement shall not be deemed to extend to Settlement Shares or Early Settlement Shares. Accordingly, each party represents and warrants to the other that (i) it has the financial ability to bear the economic risk of its investment in each Share Forward Transaction and is able to bear a total loss of its investment, (ii) it is an "accredited investor" as that term is defined under Regulation D, (iii) it will purchase each Share Forward Transaction for investment and not with a view to the distribution or resale thereof, and (iv) the disposition of each Share Forward Transaction is restricted under this Master Confirmation and each Supplemental Confirmation, the Securities Act and state securities laws.

4. *Additional Representations, Warranties and Covenants of Counterparty .*

As of the date hereof and the date of each Supplemental Confirmation, Counterparty represents, warrants and covenants to GS&Co. that:

(a) the purchase or writing of each Transaction will not violate Rule 13e-1 or Rule 13e-4 under the Securities Exchange Act of 1934, as amended (the "Exchange Act");

(b) is not entering into any Transaction on the basis of, and is not aware of, any material non-public information with respect to the Shares or in anticipation of, in connection with, or to facilitate, a distribution of its securities, a self tender offer or a third-party tender offer;

(c) it is not entering into any Transaction to create, and will not engage in any other securities or derivative transaction to create, a false or misleading appearance of active trading or market activity in the Shares (or any security convertible into or exchangeable for the Shares), or which would otherwise violate the Exchange Act;

(d) Counterparty is in compliance with its reporting obligations under the Exchange Act and its most recent Annual Report on Form 10-K, together with all reports subsequently filed by it pursuant to the Exchange Act, taken together and as amended and supplemented to the date of this representation, do not, as of their respective filing dates, contain any untrue statement of a material fact or omit any material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances in which they were made, not misleading;

(e) each Transaction is being entered into pursuant to a publicly disclosed Share buy-back program and its Board of Directors has approved the use of the Transaction to effect the Share buy-back program;

(f) notwithstanding the generality of Section 13.1 of the Equity Definitions, GS&Co. is not making any representations or warranties with respect to the treatment of any Transaction under FASB Statements 149 or 150, EITF 00-19 (or any successor issue statements) or under FASB's Liabilities & Equity Project;

(g) it has not, and during any Valuation Period (as extended pursuant to the provisions of Section 5 and "Valuation Period" herein) will not, enter into agreements similar to the Transactions described herein except with GS&Co. or an entity affiliated with GS&Co. where the valuation period in such other transaction will overlap at any time (including as a result of extensions in such valuation period as provided in the relevant agreements) with any Valuation Period (as extended pursuant to the provisions of Section 5 and "Valuation Period" herein) under this Master Confirmation. In the event that the valuation period in any other similar transaction with an entity other than GS&Co. or an entity affiliated with GS&Co. overlaps with any Valuation

Period under this Master Confirmation as a result of any extension made pursuant to the provisions of Section 5 and "Valuation Period" herein, Counterparty shall promptly amend such transaction to avoid any such overlap; and

(h) it shall report each Transaction as required under the Exchange Act and the regulations promulgated thereunder.

5. *Suspension of Valuation Period; Extension of Valuation Period* .

(a) If Counterparty concludes that it will be engaged in a distribution of the Shares for purposes of Regulation M promulgated under the Exchange Act ("Regulation M"), Counterparty agrees that it will, on one Scheduled Trading Day's written notice, direct GS&Co. not to purchase Shares in connection with hedging any Transaction during the "restricted period" (as defined in Regulation M). If on any Scheduled Trading Day Counterparty delivers written notice (and confirms by telephone) by 8:30 a.m. New York Time (the "Notification Time"), then such notice shall be effective to suspend the Valuation Period as of such Notification Time. In the event that Counterparty delivers notice and/or confirms by telephone after the Notification Time, then the Valuation Period shall be suspended effective as of 8:30 a.m. New York Time on the following Scheduled Trading Day or as otherwise required by law or agreed between Counterparty and GS&Co. The Valuation Period shall be suspended and the Valuation Date extended for each Scheduled Trading Day in such restricted period.

(b) In the event that GS&Co. concludes, in its reasonable discretion, that it is appropriate with respect to any legal, regulatory or self-regulatory requirements or related policies and procedures (whether or not such requirements, policies or procedures are imposed by law or have been voluntarily adopted by GS&Co.), for it to refrain from purchasing Shares on any Scheduled Trading Day during the Valuation Period, GS&Co. may by written notice to Counterparty elect to suspend the Valuation Period for such number of Scheduled Trading Days as is specified in the notice. The notice shall not specify, and GS&Co. shall not otherwise communicate to Counterparty, the reason for GS&Co.'s election to suspend the Valuation Period. The Valuation Period shall be suspended and the Valuation Date extended for each Scheduled Trading Day occurring during any such suspension.

(c) In the event that the Valuation Period is suspended pursuant to Sections 5(a) or (b) above during the regular trading session on the Exchange, then the Calculation Agent in its sole discretion shall, in calculating the Forward Cash Settlement Amount, extend the Valuation Period and make adjustments to the weighting of each Relevant Price for purposes of determining the Settlement Price, with such adjustments based on, among other factors, the duration of any such suspension and the volume, historical trading patterns and price of the Shares.

(d) On the first Exchange Business Day of each calendar week during the Valuation Period, to the extent that the Number of Daily Reference Shares exceeds 25% of the ADTV (as defined in Rule 10b-18 under the Exchange Act ("Rule 10b-18")) for the Shares on such day, the Calculation Agent will (i) adjust the Number of Daily Reference Shares to equal an amount equal to 15% of ADTV for the Shares determined and effective on such Exchange Business Day and (ii) deem the remaining Scheduled Trading Days in the Valuation Period to be equal to the Remaining Number of Shares divided by the Number of Daily Reference Shares (after giving effect to any adjustments pursuant to (i) above), rounded up to the nearest whole number.

"Number of Daily Reference Shares" means, for each Transaction, initially the Initial Number of Daily Reference Shares (as set forth in the Supplemental Confirmation) and thereafter as may be adjusted in accordance with this Section 5(d); provided that on the first Exchange Business Day of the fifth calendar week following any such adjustment the Number of Daily Reference Shares shall equal

the lesser of (i) the Initial Number of Daily Reference Shares and (ii) 15% of the ADTV of the Shares determined on such Exchange Business Day.

"Remaining Number of Shares" means, for each Transaction and as of any date of determination, a number of Shares equal to (i) the Number of Shares minus (ii) the sum of, for each Exchange Business Day in the Valuation Period up to and including such date, the Number of Shares divided by the total number of Exchange Business Days in the Valuation Period (the "Daily Amount"). The Daily Amount will be deemed to be zero for each day on which the Valuation Period is suspended in accordance with Sections 5(a) and (b) hereof. In the event that the Valuation Period is extended pursuant to the terms of this Master Confirmation, the Calculation Agent may make corresponding adjustments to the amount of the Remaining Number of Shares.

6. *Counterparty Purchases* . Counterparty represents, warrants and covenants to GS&Co. that for each Transaction:

(a) Counterparty (or any "affiliated purchaser" as defined in Rule 10b-18) shall not, purchase any Shares, listed contracts on the Shares or securities that are convertible into, or exchangeable or exercisable for Shares (including, without limitation, any Rule 10b-18 purchases of blocks (as defined in Rule 10b-18)) during any Valuation Period (as extended pursuant to the provisions of Section 5 and "Valuation Period" herein) except for purchases through GS&Co. or an entity affiliated with GS&Co., or if not through GS&Co., with the prior written consent of GS&Co., and in compliance with Rule 10b-18 or otherwise in a manner that Counterparty and GS&Co. believe is in compliance with applicable requirements and except for purchases in connection with management compensation plans or other employee benefit arrangements and except for purchases of the Counterparty's 9.50% Convertible Subordinated Notes due 2010, provided such purchases are made in compliance with any applicable legal regulatory or self-regulatory requirements or related policies and procedures (whether such requirements, policies or procedures are imposed by law or have been voluntarily adopted by GS&Co. for uniform application to all such purchases). Any such purchase by Counterparty shall be disregarded for purposes of determining the Forward Cash Settlement Amount. To the extent that Counterparty makes any such purchase other than through GS&Co., or other than in connection with any Transaction, Counterparty hereby represents and warrants to GS&Co. that (a) it will not take other action that would or could cause GS&Co.'s purchases of the Shares during the Valuation Period not to comply with Rule 10b-18 and (b) any such purchases will not otherwise constitute a violation of Section 9(a) or Rule 10(b) of the Exchange Act. This subparagraph (a) shall not restrict any purchases by Counterparty of Shares effected during any suspension of any Valuation Period in accordance with Section 5 herein and any purchases during such suspension shall be disregarded in calculating the Forward Cash Settlement Amount; and for the avoidance of doubt, this subparagraph (a) shall not restrict any holders of outstanding securities of the Counterparty from exercising or converting such securities to Shares; and

(b) Counterparty is entering into this Master Confirmation and each Transaction hereunder in good faith and not as part of a plan or scheme to evade the prohibitions of Rule 10b5-1 under the Exchange Act ("Rule 10b5-1"). It is the intent of the parties that each Transaction entered into under this Master Confirmation comply with the requirements of Rule 10b5-1(c)(1)(i)(A) and (B) and each Transaction entered into under this Master Confirmation shall be interpreted to comply with the requirements of Rule 10b5-1(c). Counterparty will not seek to control or influence GS&Co. to make "purchases or sales" (within the meaning of Rule 10b5-1(c)(1)(i)(B) (3)) under any Transaction entered into under this Master Confirmation, including, without limitation, GS&Co.'s decision to enter into any hedging transactions. Counterparty represents and warrants that it has consulted with its own advisors as to the legal aspects of its adoption and implementation of this Master Confirmation and each Supplemental Confirmation under Rule 10b5-1.

7. *Additional Termination Events* . Additional Termination Events will apply under Section 5(b)(v) of the Agreement. The following will constitute Additional Termination Events, in each case with Counterparty as the sole Affected Party:

(a) Notwithstanding anything to the contrary in the Equity Definitions, the occurrence of a Nationalization, Insolvency or a Delisting (in each case effective on the Announcement Date as determined by the Calculation Agent);

(b) Notwithstanding anything to the contrary in the Equity Definitions, the occurrence of a Merger Event (effective on the Merger Date) or a Tender Offer (effective on the Tender Offer Date) in respect of which any Other Consideration received for the Shares does not consist of cash. For the avoidance of doubt, in the event that any portion of the consideration received for the Shares consists of cash or New Shares, this Additional Termination Event shall only apply with respect to all or any Transaction(s) (or portions thereof) remaining after giving effect to the provisions in "Consequences of Merger Events" or "Consequences of Tender Offers", as the case may be, above;

(c) [reserved]; or

(d) Notwithstanding anything to the contrary in the Equity Definitions, one day prior to the ex-dividend date in respect of any Extraordinary Dividend (as specified in the Supplemental Confirmation) by the Issuer; provided that in the event that GS&Co. and Counterparty enter into a mutually acceptable new transaction (using their good faith and commercially reasonable efforts) on or prior to one day prior to the ex-dividend date in respect of the amount determined pursuant to Section 6(e) of the Agreement or otherwise with respect to the Affected Transaction(s) shall be deemed to be zero. For the avoidance of doubt, in the event that an Early Termination Date would otherwise occur pursuant to this clause 7(d) while the Counterparty is in possession of, or is aware of, material, non-public information, the Early Termination Date shall not be deemed to occur until the day after the day on which Counterparty is not in possession of, and is not aware of, material non-public information.

8. *Automatic Termination Provisions* . Notwithstanding anything to the contrary in Section 6 of the Agreement:

(a) An Additional Termination Event with Counterparty as the sole Affected Party will automatically occur without any notice or action by GS&Co. or Counterparty if the price of the Shares on the Exchange at any time falls below the Termination Price (as specified in the related Supplemental Confirmation) provided that (for the avoidance of doubt only) such Additional Termination Event shall be an Additional Termination Event only with respect to the Transaction documented in such related Supplemental Confirmation. The Exchange Business Day that the price of the Shares on the Exchange at any time falls below the Termination Price will be the "Early Termination Date" for purposes of the Agreement.

(b) Notwithstanding anything to the contrary in Section 6(d) of the Agreement, following the occurrence of such an Additional Termination Event, GS&Co. will notify Counterparty of the amount owing under Section 6(e) of the Agreement within a commercially reasonable time period (with such period based upon the amount of time, determined by GS&Co. (or any of its Affiliates) in its reasonable discretion, that it would take to unwind any of its Hedge Position(s) related to the Transaction in a commercially reasonable manner based on relevant market indicia). For purposes of the "Net Share Settlement Upon Early Termination" provisions herein, (i) the date that such notice is effective (the "Notice Date") shall constitute the "Net Share Valuation Date", (ii) the Exchange Business Day immediately following the Notice Date shall be the Net Share Settlement Date and (iii) all references to the Forward Cash Amount or the Fixed Amount in Annex B hereto shall be deemed to be the Early Termination Amount. For the avoidance of

doubt, Hedge Position shall only mean any purchase, sale, entry into or maintenance of one or more stock borrowing transactions by GS&Co. or its Affiliates in respect of the Shares in connection with this Transaction and, notwithstanding the forgoing portions of this paragraph and Sections 6(d) and (e) of the Agreement, Counterparty shall be entitled to satisfy the Hedge Position by delivery of the Number of Early Settlement Shares as defined in and pursuant to the provisions of Section 10.

9. *Special Provisions for Merger Events* . Notwithstanding anything to the contrary herein or in the Equity Definitions, to the extent that an Announcement Date for a potential Merger Transaction occurs during any Valuation Period:

(a) Promptly after request from GS&Co., Counterparty shall provide GS&Co. with written notice specifying (i) Counterparty's average daily Rule 10b-18 Purchases (as defined in Rule 10b-18) during the three full calendar months immediately preceding the Announcement Date that were not effected through GS&Co. or its affiliates and (ii) the number of Shares purchased pursuant to the proviso in Rule 10b-18(b)(4) under the Exchange Act for the three full calendar months preceding the Announcement Date. Such written notice shall be deemed to be a certification by Counterparty to GS&Co. that such information is true and correct. Counterparty understands that GS&Co. will use this information in calculating the trading volume for purposes of Rule 10b-18; and

(b) GS&Co. in its sole discretion may (i) make adjustments to the terms of any Transaction, including, without limitation, the Valuation Date and the Number of Shares to account for the number of Shares that could be purchased on each day during the Valuation Period in compliance with Rule 10b-18 following the Announcement Date or (ii) treat the occurrence of the Announcement Date as an Additional Termination Event with Counterparty as the sole Affected Party.

"Merger Transaction" means any merger, acquisition or similar transaction involving a recapitalization as contemplated by Rule 10b-18(a) (13)(iv) under the Exchange Act.

10. *Special Settlement Following Early Termination and Extraordinary Events* . Notwithstanding anything to the contrary in this Master Confirmation or any Supplemental Confirmation hereunder, in the event that an Extraordinary Event under Article 12 of the Equity Definitions occurs or an Early Termination Date under Section 6 of the Agreement occurs or is designated with respect to any Transaction (each an "Affected Transaction"), then either party may elect, by notice to the other party, to have Counterparty deliver the Number of Early Settlement Shares to GS&Co. on the date that such notice is effective (provided that GS&Co. determines in its good faith sole discretion that such delivery is in compliance with any legal, regulatory or self-regulatory requirements or related policies and procedures), except for a termination as a result of Section 7(d), in which event the date of delivery shall be the tenth Business Day thereafter. To the extent that Counterparty elects to deliver Shares to GS&Co. accompanied by an effective Registration Statement (satisfactory to GS&Co. in its reasonable discretion) covering such Early Settlement Shares, Counterparty must be in compliance with the conditions specified in (iii) though (ix) in Annex B hereto at the time of such delivery. If Counterparty elects to deliver Unregistered Shares (as defined in Annex B) to GS&Co., Counterparty and GS&Co. will negotiate in good faith on acceptable procedures and documentation relating to the sale of such Unregistered Shares.

"Number of Early Settlement Shares" means a number of Shares based on the Hedge Positions of GS&Co. or any of its Affiliates' with respect to each Affected Transaction under this Master Confirmation at the time of the Extraordinary Event or Early Termination Date, as applicable.

In determining the amount of Loss under Section 6(e) of the Agreement or the Cancellation Amount under Article 12, the parties shall take into account the Floating Rate Amount that would

have otherwise been due to the Counterparty and the Fixed Amount that would have otherwise been due to GS&Co., and the difference between the New York 10b-18 Volume Weighted Average Price per share of the Shares over the Valuation Period as compared to the Forward Price. Further, if Counterparty delivers Early Settlement Shares, an amount equal to the product of (i) the Number of Early Settlement Shares multiplied by (ii) the Forward Price (or if Counterparty delivers Unregistered Shares, as reduced by a discount determined by GS&Co. in a good faith commercially reasonable manner based on the discount to the New York 10b-18 Volume Weighted Average Price at which it could sell the Shares and whether GS&Co. and Counterparty have agreed on acceptable procedures and documentation relating to such Unregistered Shares as described above) shall be credited against any amount owing under Section 6(e) of the Agreement or pursuant to Article 12 of the Equity Definitions or otherwise under this Master Confirmation.

11. *Acknowledgments* . The parties hereto intend for:

(a) Each Transaction to be a "securities contract" as defined in Section 741(7) of the U.S. Bankruptcy Code (Title 11 of the United States Code) (the "Bankruptcy Code"), a "swap agreement" as defined in Section 101(53B) of the Bankruptcy Code, or a "forward contract" as defined in Section 101(25) of the Bankruptcy Code, and the parties hereto to be entitled to the protections afforded by, among other Sections, Sections 362(b)(6), 362(b)(17), 555, 556, and 560 of the Bankruptcy Code;

(b) A party's right to liquidate or terminate any Transaction, net out or offset termination values of payment amounts, and to exercise any other remedies upon the occurrence of any Event of Default under the Agreement with respect to the other party to constitute a "contractual right" (as defined in the Bankruptcy Code);

(c) All payments for, under or in connection with each Transaction, all payments for the Shares and the transfer of such Shares to constitute "settlement payments" and "transfers" (as defined in the Bankruptcy Code).

12. *Set-Off* . The parties agree to amend Section 6 of the Agreement by adding a new Section 6(f) thereto as follows:

"(f) Upon the occurrence of an Event of Default or Termination Event with respect to a party who is the Defaulting Party or the Affected Party ("X"), the other party ("Y") will have the right (but not be obliged) without prior notice to X or any other person to set-off or apply any obligation of X owed to Y (whether or not matured or contingent and whether or not arising under the Agreement, and regardless of the currency, place of payment or booking office of the obligation) against any obligation of Y owed to X (whether or not matured or contingent and whether or not arising under the Agreement, and regardless of the currency, place of payment or booking office of the obligation). Y will give notice to the other party of any set-off effected under this Section 6(f).

Amounts (or the relevant portion of such amounts) subject to set-off may be converted by Y into the Termination Currency at the rate of exchange at which such party would be able, acting in a reasonable manner and in good faith, to purchase the relevant amount of such currency. If any obligation is unascertained, Y may in good faith estimate that obligation and set-off in respect of the estimate, subject to the relevant party accounting to the other when the obligation is ascertained. Nothing in this Section 6 (f) shall be effective to create a charge or other security interest. This Section 6(f) shall be without prejudice and in addition to any right of set-off, combination of accounts, lien or other right to which any party is at any time otherwise entitled (whether by operation of law, contract or otherwise)."

13. *Payment Date Upon Early Termination* . Notwithstanding anything to the contrary in Section 6(d)(ii) of the Agreement, all amounts calculated as being due in respect of an Early

Termination Date under Section 6(e) of the Agreement will be payable on the day that notice of the amount payable is effective, except as otherwise provided in this Master Confirmation or any Supplemental Confirmation.

14. *Share Settlement; Maximum Shares* . Notwithstanding anything contained in this Master Confirmation, the Agreement or the Equity Definitions, Counterparty may satisfy all amounts it may owe GS&Co. hereunder and under each Supplemental Confirmation by delivery of Shares in accordance with Annex B and/or Section 10 hereof, and is solely vested with the right to determine whether to satisfy its obligations in Shares, in cash or in a combination of the two. Notwithstanding anything contained in this Master Confirmation, the Agreement or the Equity Definitions, Counterparty and GS&Co. agree that if Counterparty elects to satisfy its obligations to GS&Co. by delivery of Shares, the delivery of a number of Shares equal to the Reserved Shares will satisfy in full the obligation of Counterparty to make any payments pursuant to Section 6(e) of the Agreement, Article 12 of the Equity Definitions or otherwise in respect of the Transaction.

15. *Governing Law* . The Agreement, this Master Confirmation and each Supplemental Confirmation and all matters arising in connection with the Agreement, this Master Confirmation and each Supplemental Confirmation shall be governed by, and construed and enforced in accordance with, the law of the State of New York without reference to its choice of law doctrine.

16. *Offices* .

(a) The Office of GS&Co. for each Transaction is: One New York Plaza, New York, New York 10004.

(b) The Office of Counterparty for each Transaction is: One Market Spear Tower, Suite 2400 San Francisco, CA 94105.

17. *Arbitration* .

(a) **Arbitration is final and binding on Counterparty and GS&Co.**

(b) **Counterparty and GS&Co. are waiving their right to seek remedies in court, including the right to a jury trial.**

(c) **Pre-arbitration discovery is generally more limited than and different from court proceedings.**

(d) **The arbitrator's award is not required to include factual findings or legal reasoning and any party's right to appeal or to seek modification of rulings by the arbitrators is strictly limited.**

(e) **The panel of arbitrators will typically include a minority of arbitrators who were or are affiliated with the securities industry.**

Any controversy between or among GS&Co. or its affiliates, or any of its or their partners, directors, agents or employees, on the one hand, and Counterparty or its agents and affiliates, on the other hand, arising out of or relating to the Agreement or any Transaction entered into hereunder, shall be settled by arbitration, in accordance with the then current rules of the American Arbitration Association ("AAA"), except that the provisions of this Section 17 shall supersede any conflicting or inconsistent provisions of such rules. Each party shall appoint a qualified arbitrator within 5 days after the giving of notice by either party. If either party shall fail timely to appoint a qualified arbitrator, the appointed, qualified arbitrator shall select the second qualified arbitrator within 5 days after such party's failure to appoint. The qualified arbitrators so appointed shall meet and shall, if possible, determine such matter within 10 days after the second qualified arbitrator is appointed, and their determination shall be binding on the parties. If for any reason such two qualified arbitrators fail to agree on such matter within such period of 10 days, then either party may request the AAA to appoint a qualified arbitrator who shall be impartial within 7 days of such request and both parties

shall be bound by any appointment so made by the AAA. Within 7 days after the third qualified arbitrator has been appointed, each of the first two qualified arbitrators shall submit their respective determinations to the third qualified arbitrator who must select one or the other of such determinations (whichever the third qualified arbitrator believes to be correct or closest to a correct determination) within 7 days after the first two qualified arbitrators shall have submitted their respective determinations to the third qualified arbitrator, and the selection so made shall in all cases be binding upon the parties, and judgment upon such decision may be entered into any court having jurisdiction. In the event of the failure, refusal or inability of a qualified arbitrator to act, a successor shall be appointed within 10 days as hereinbefore provided. The costs of the arbitration shall be funded 50% by each party, and the parties shall bear their own attorneys' fees, during the arbitration. The prevailing party shall be repaid all of such expenses by the non-prevailing party within 10 days after the final determination of the qualified arbitrator(s). The award of the arbitrators shall be final, and judgment upon the award rendered may be entered in any court, state or Federal, having jurisdiction.

Neither party shall bring a putative or certified class action to arbitration, nor seek to enforce any pre-dispute arbitration agreement against any person who has initiated in court a putative class action; who is a member of a putative class who has not opted out of the class with respect to any claims encompassed by the putative class action until:

- (i) the class certification is denied;
- (ii) the class is decertified; or
- (iii) the party is excluded from the class by the court.

Such forbearance to enforce an agreement to arbitrate shall not constitute a waiver of any rights under the Agreement except to the extent stated herein.

18. Counterparty hereby agrees (a) to check this Master Confirmation carefully and immediately upon receipt so that errors or discrepancies can be promptly identified and rectified and (b) to confirm that the foregoing (in the exact form provided by GS&Co.) correctly sets forth the terms of the agreement between GS&Co. and Counterparty with respect to any Transaction, by manually signing this Master Confirmation or this page hereof as evidence of agreement to such terms and providing the other information requested herein and immediately returning an executed copy to Equity Derivatives Documentation Department, facsimile No. 212-428-1980/83.

[SIGNATURE PAGE FOLLOWS]

Authorized Signatory

Agreed and Accepted

By: **PG&E CORPORATION**

By: /s/ LEROY BARNES JR.

Name: Leroy Barnes, Jr.

Title: *VP Treasurer*

ANNEX A

SUPPLEMENTAL CONFIRMATION FOR FULLY UNCOLLARED TRANSACTIONS

To: PG&E Corporation
One Market Spear Tower
Suite 2400
San Francisco, CA 94105

From: Goldman, Sachs & Co.

Subject: Accelerated Share Repurchase Transaction—VWAP Pricing

Ref. No: **EN41JA000000000**

Date: **December 16, 2004**

This Supplemental Confirmation amends and supercedes any previous

Supplemental Confirmation relating to this Transaction

The purpose of this Supplemental Confirmation is to confirm the terms and conditions of the Transaction entered into between Goldman, Sachs & Co. ("GS&Co.") and PG&E Corporation ("Counterparty") (together, the "Contracting Parties") on the Trade Date specified below. This Supplemental Confirmation is a binding contract between GS&Co. and Counterparty as of the relevant Trade Date for the Transaction referenced below.

1. This Supplemental Confirmation supplements, forms part of, and is subject to the Master Confirmation dated as of December 15, 2004 (the "Master Confirmation") between the Contracting Parties, as amended and supplemented from time to time. The definitions and provisions contained in the Master Confirmation are incorporated into this Supplemental Confirmation, except as expressly modified below. In the event of any inconsistency between those definitions and provisions and this Supplemental Confirmation, this Supplemental Confirmation will govern.

2. The terms of the Transaction to which this Supplemental Confirmation relates are as follows:

Trade Date:	December 15, 2004. In a related transaction Counterparty agreed to purchase a number of Shares equal to the Number of Shares from GS&Co. on the Trade Date at the Forward Price per Share.
Forward Price:	USD \$32.50 per Share
Valuation Period Start Date:	The Scheduled Trading Day following the Trade Date.
Valuation Date:	February 16, 2005
Number of Shares:	9,769,600 Shares
Termination Price:	\$10 per Share
Fixed Rate:	25 basis points
Reserved Shares:	A number of Shares equal to two times the Number of Shares.

Extraordinary Dividends:

Any cash dividend declared by the Issuer in excess of
\$0.00 per Share.

Initial Number of Daily Reference Shares:

227,200 shares

Initial Notional Amount:

\$317,512,000.00

3. Counterparty represents and warrants to GS&Co. that neither it (nor any "affiliated purchaser" as defined in Rule 10b-18 under the Exchange Act) have made any purchases of blocks except through GS&Co. or an entity affiliated with GS&Co. pursuant to the proviso in Rule 10b-18(b)(4) under the Exchange Act during the four full calendar weeks immediately preceding the Trade Date.

Counterparty hereby agrees (a) to check this Supplemental Confirmation carefully and immediately upon receipt so that errors or discrepancies can be promptly identified and rectified and (b) to confirm that the foregoing (in the exact form provided by GS&Co.) correctly sets forth the terms of the agreement between GS&Co. and Counterparty with respect to this Transaction, by manually signing this Supplemental Confirmation or this page hereof as evidence of agreement to such terms and providing the other information requested herein and immediately returning an executed copy to Equity Derivatives Documentation Department, facsimile No. 212-428-1980/83.

Yours sincerely,

GOLDMAN, SACHS & CO.

By: /s/ VANESSA MARLING

Authorized Signatory

Agreed and Accepted

By: **PG&E CORPORATION**

By: /s/ LEROY BARNES JR.

Name: Leroy Barnes, Jr.

Title: *VP Treasurer*

ANNEX B

NET SHARE SETTLEMENT PROCEDURES

The following Net Share Settlement Procedures shall apply to the extent that Counterparty elects Net Share Settlement in accordance with the Master Confirmation:

Net Share Settlement shall be made by delivery of the number of Shares equal in value to the Forward Cash Settlement Amount plus the Fixed Amount (the "Settlement Shares"), with such Shares' value based on the Net Share Settlement Price. Delivery of such Settlement Shares shall be made free of any contractual or other restrictions in good transferable form (other than under the Securities Act with respect to any Unregistered Shares (as defined below)) on the Net Share Settlement Date with Counterparty (i) representing and warranting to GS&Co. at the time of such delivery that it has good, valid and marketable title or right to sell and transfer all such Shares to GS&Co. under the terms of the related Transaction free of any lien charge, claim or other encumbrance and (ii) making the representations and agreements contained in Section 9.11(ii) through (iv) of the Equity Definitions to GS&Co. with respect to the Settlement Shares. GS&Co. or any affiliate of GS&Co. designated by GS&Co. (GS&Co. or such affiliate, "GS") shall resell the Settlement Shares during a period (the "Resale Period") commencing no earlier than the Exchange Business Day on which the Settlement Shares are delivered. GS shall use its good faith, commercially reasonable efforts to sell the Settlement Shares as promptly as possible at commercially reasonable prices based on prevailing market prices for the Shares. The Resale Period shall end on the Exchange Business Day on which GS completes the sale of all Settlement Shares or a sufficient number of Settlement Shares so that the realized net proceeds of such sales exceed the Forward Cash Settlement Amount plus the Fixed Amount. Notwithstanding the foregoing, if resale by GS of the Settlement Shares, as determined by GS in its sole discretion (i) occurs during a distribution for purposes of Regulation M, and if GS would be subject to the restrictions of Rule 101 of Regulation M in connection with such distribution, the Resale Period will be postponed or tolled, as the case may be, until the Exchange Business Day immediately following the end of any "restricted period" as such term is defined in Regulation M with respect to such distribution under Regulation M or (ii) conflict with any legal, regulatory or self-regulatory requirements or related policies and procedures applicable to GS (whether or not such requirements, policies or procedures are imposed by law or have been voluntarily adopted by GS), the Resale Period will be postponed or tolled, as the case may be, until such conflict is no longer applicable. During the Resale Period, if the realized net proceeds from the resale of the Settlement Shares exceed the Forward Cash Settlement Amount plus the Fixed Amount, GS shall refund such excess in cash to Counterparty by the close of business on the third Exchange Business Day immediately following the last day of the Resale Period. If the Forward Cash Settlement Amount plus the Fixed Amount exceeds the realized net proceeds from such resale, Counterparty shall transfer to GS by the open of the regular trading session on the Exchange on the third Scheduled Trading Day immediately following the last day of the Resale Period the amount of such excess (the "Additional Amount") in the number of Shares ("Make-whole Shares") in an amount that, based on the Net Share Settlement Price on the last day of the Resale Period (as if such day was the "Net Share Valuation Date" for purposes of computing such Net Share Settlement Price), has a dollar value equal to the Additional Amount. The Resale Period shall continue to enable the sale of the Make-whole Shares. The requirements and provisions set forth below shall apply to Shares delivered to pay such Additional Amounts. This provision shall be applied successively until the Additional Amount is equal to zero.

Net Share Settlement of a Transaction is subject to the following conditions:

Counterparty at its sole expense shall:

(i) as promptly as practicable (but in no event more than five (5) Exchange Business Days immediately following the Settlement Method Election Date or, in the case of an election of Net Share Settlement upon the occurrence of an Extraordinary Event or an Early Termination Date,

no more than one Exchange Business Day immediately following either the Cancellation Date or the Early Termination Date, as the case may be) file under the Securities Act and use its best efforts to make effective, as promptly as practicable, a registration statement or supplement or amend an outstanding registration statement, in any such case, in form and substance reasonably satisfactory to GS (the "Registration Statement") covering the offering and sale by GS of not less than 150% of the Shares necessary to fulfill the Net Share Settlement delivery obligation by Counterparty (determining the number of such Shares to be registered on the basis of the average of the Settlement Prices on the five (5) Exchange Business Days prior to the date of such filing, amendment or supplement, as the case may be);

(ii) maintain the effectiveness of the Registration Statement until GS has sold all shares to be delivered by Counterparty necessary to satisfy its Net Share Settlement obligations;

(iii) have afforded GS and its counsel and other advisers a reasonable opportunity to conduct a due diligence investigation of Counterparty customary in scope for transactions in which GS acts as underwriter of equity securities, and GS shall have been satisfied (with the approval of its Commitments Committee in accordance with its customary review process) with the results of such investigation;

(iv) have negotiated and entered into an agreement with GS providing for such covenants, conditions, representations and warranties, underwriting discounts, commissions, indemnities and contribution rights as are customary for GS equity underwriting agreements, together with customary certificates and opinions of counsel and letters of independent auditors of Counterparty to be delivered to GS covering the shares to be delivered by Counterparty in satisfaction of its Net Share Settlement obligations;

(v) have delivered to GS such number of prospectuses relating thereto as GS shall have reasonably requested and shall promptly update and provide GS with replacement prospectuses as necessary to ensure the prospectus does not contain any untrue statement of a material fact or any omission of a material fact required to be stated therein or necessary to make the statements therein, in the light of the circumstances in which they were made, not misleading;

(vi) have retained for GS nationally-recognized underwriting counsel acceptable to GS (in its sole discretion) with broad experience in similar registered securities offerings and such counsel shall have agreed to act as such;

(vii) have taken all steps necessary for the shares sold by GS to be listed or quoted on the primary exchange or quotation system that the Shares are listed or quoted on;

(viii) have paid all reasonable and actual out-of-pocket costs and expenses of GS and all reasonable and actual fees and expenses of GS's outside counsel and other independent experts in connection with the foregoing; and

(ix) take such action as is required to ensure that GS's sale of the Shares does not violate, or result in a violation of, the federal or state securities laws.

In the event that the Registration Statement is not declared effective by the Securities Exchange Commission (the "SEC") or any of the conditions specified in (ii) through (ix) above are not satisfied on or prior to the Valuation Date (or, in the case of an election of Net Share Settlement upon the occurrence of an Extraordinary Event or an Early Termination Date, on or prior to the first Exchange Business Day following either the Cancellation Date or the Early Termination Date, as the case may be except for any Early Termination as result of Section 7(d) of the Master Confirmation, in which case, such date shall be the tenth Exchange Business Day following such Early Termination Date), then Counterparty may deliver Unregistered Shares to GS in accordance with the following conditions. If GS and Counterparty can agree on acceptable pricing, procedures and documentation relating to the sale

of such Unregistered Shares (including, without limitation, applicable requirements in (iii) through (ix) above and insofar as pertaining to private offerings), then such Unregistered Shares shall be deemed to be the "Settlement Shares" for the purposes of the related Transaction and the settlement procedure specified in this Annex B shall be followed except that in the event that the Forward Cash Settlement Amount plus the Fixed Amount, exceeds the proceeds from the sale of such Unregistered Shares then for the purpose of calculating the number of "Make-whole Shares" to be delivered by Counterparty, GS shall determine the discount to the Net Share Settlement Price at which it can sell the Unregistered Shares. Notwithstanding the delivery of the Unregistered Shares, Counterparty shall endeavor in good faith to have a registration statement declared effective by the SEC as soon as practical. In the event that GS has not sold sufficient Unregistered Shares to satisfy Counterparty's obligations to GS contained herein at the time that a Registration Statement covering the offering and sale by GS of a number of Shares equal in value to not less than 150% of the amount then owed to GS is declared effective (based on the Net Share Settlement Price on the Exchange Business Day (as if such Exchange Business Day were the "Net Share Valuation Date" for purposes of computing such Net Share Settlement Price) that the Registration Statement was declared effective), GS shall return all unsold Unregistered Shares to Counterparty and Counterparty shall deliver such number of Shares covered by the effective Registration Statement equal to 100% of the amount then owed to GS based on such Net Share Settlement Price. Such delivered shares shall be deemed to be the "Settlement Shares" for the purposes of the related Transaction and the settlement procedure specified in this Master Confirmation, including, without limitation, this Annex B, (including the obligation to deliver any Make-whole Shares, if applicable) shall be followed. In all cases GS shall be entitled to take any and all required actions in the course of its sales of the Settlement Shares, including without limitation making sales of the Unregistered Shares only to "Qualified Institutional Buyers" (as such term is defined under the Securities Act), to ensure that the sales of the Unregistered Shares and the Settlement Shares covered by the Registration Statement are not integrated resulting in a violation of the securities laws and Counterparty agrees to take all actions requested by GS in furtherance thereof.

If GS and Counterparty cannot agree on acceptable pricing, procedures and documentation relating to the sales of such Unregistered Shares then the number of Unregistered Shares to be delivered to GS pursuant to the provisions above shall not be based on the Net Share Settlement Price but rather GS shall determine the value attributed to each Unregistered Share in a commercially reasonable manner and based on such value Counterparty shall deliver a number of Shares equal in value to the Forward Cash Settlement Amount plus the Fixed Amount. For the purposes hereof "Unregistered Shares" means Shares that have not been registered pursuant to an effective registration statement under the Securities Act or any state securities laws ("Blue Sky Laws") and that cannot be sold, transferred, pledged or otherwise disposed of without registration under the Securities Act or under applicable Blue Sky Laws unless such sale, transfer, pledge or other disposition is made in a transaction exempt from registration thereunder.

In the event that Counterparty delivers Shares pursuant to an election of Net Share Settlement then Counterparty agrees to indemnify and hold harmless GS, its affiliates and its assignees and their respective directors, officers, employees, agents and controlling persons (GS and each such person being an "Indemnified Party") from and against any and all losses, claims, damages and liabilities (or actions in respect thereof), joint or several, to which such Indemnified Party may become subject, under the Securities Act or otherwise, (i) relating to or arising out of any of the Transactions contemplated by this Master Confirmation concerning Net Share Settlement or (ii) arising out of or based upon any untrue statement or alleged untrue statement of a material fact contained in any preliminary prospectus, prospectus, Registration Statement or other written material relating to the Shares delivered to prospective purchasers, including in each case any amendments or supplements thereto and including but not limited to any documents deemed to be incorporated in any such document by reference (the "Offering Materials"), or arising out of or based upon any omission or alleged omission to state in the Offering Materials a material fact necessary in order to make the statements therein, in

the light of the circumstances under which they were made, not misleading; provided, however, that, in the case of this clause (ii), Counterparty will not be liable to the extent that any loss, claim, damage or liability arises out of or is based upon any untrue statement or omission or alleged untrue statement or omission in the Offering Materials made in reliance upon and in conformity with written information furnished to Counterparty by GS expressly for use in the Offering Materials, as expressly identified in a letter to be delivered at the closing of the delivery of Shares by Counterparty to GS. The foregoing indemnity shall exclude losses that GS incurs solely by reason of the proceeds from the sale of the Capped Number of Shares being less than the Forward Cash Settlement Amount. Counterparty will not be liable under the foregoing indemnification provision to the extent that any loss, claim, damage, liability or expense is found in a nonappealable judgment by a court of competent jurisdiction to have resulted from GS's willful misconduct, gross negligence or bad faith in performing the services that are subject of this Master Confirmation or from information provided in writing by GS for inclusion in the Registration Statement. If for any reason the foregoing indemnification is unavailable to any Indemnified Party or insufficient to hold harmless any Indemnified Party, then Counterparty shall contribute, to the maximum extent permitted by law, to the amount paid or payable by the Indemnified Party as a result of such loss, claim, damage or liability. In addition, Counterparty will reimburse any Indemnified Party for all expenses (including reasonable counsel fees and expenses) as they are incurred (after notice to Counterparty) in connection with the investigation of, preparation for or defense or settlement of any pending or threatened claim or any action, suit or proceeding arising therefrom, whether or not such Indemnified Party is a party thereto and whether or not such claim, action, suit or proceeding is initiated or brought by or on behalf of Counterparty. Counterparty also agrees that no Indemnified Party shall have any liability to Counterparty or any person asserting claims on behalf of or in right of Counterparty in connection with or as a result of any matter referred to in the Agreement or this Master Confirmation concerning Net Share Settlement except to the extent that any losses, claims, damages, liabilities or expenses incurred by Counterparty result from the gross negligence, willful misconduct or bad faith of the Indemnified Party. This indemnity shall survive the completion of any Transaction contemplated by this Master Confirmation and any assignment and delegation of a Transaction made pursuant to this Master Confirmation or the Agreement shall inure to the benefit of any permitted assignee of GS&Co.

In no event shall the number of Settlement Shares (including, but without duplication or double counting, any Unregistered Shares) and any Make-whole Shares, be greater than the Reserved Shares minus the amount of any Shares actually delivered under any other Transaction(s) under this Master Confirmation (the result of such calculation, the "Capped Number"). Counterparty represents and warrants (which shall be deemed to be repeated on each day that a Transaction is outstanding) that the Capped Number is equal to or less than the number of Shares determined according to the following formula:

$$A - B$$

Where A = the number of authorized but unissued shares of the Issuer that are not reserved for future issuance on the date of the determination of the Capped Number; and

 B = the maximum number of Shares required to be delivered to third parties if Counterparty elected Net Share Settlement of all transactions in the Shares (other than Transactions in the Shares under this Master Confirmation) with all third parties that are then currently outstanding and unexercised.

QuickLinks

[Exhibit 10.3](#)

[ANNEX A SUPPLEMENTAL CONFIRMATION FOR FULLY UNCOLLARED TRANSACTIONS](#)
[ANNEX B NET SHARE SETTLEMENT PROCEDURES](#)

[QuickLinks](#) -- Click here to rapidly navigate through this document

Exhibit 10.8

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION
FERC ELECTRIC TARIFF NO. 7
SECOND REPLACEMENT TRANSMISSION CONTROL AGREEMENT

TRANSMISSION CONTROL AGREEMENT

**Among
The Independent System Operator
and
Transmission Owners**

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TRANSMISSION CONTROL AGREEMENT

Among The Independent System Operator and Transmission Owners

The Parties to this Transmission Control Agreement ("Agreement") first dated as of _____, _____, are

(1) The California Independent System Operator Corporation, a California nonprofit public benefit Corporation (the "Independent System Operator" or "ISO" which expression includes its permitted successors); and

(2) Entities owning or holding Entitlements to transmission lines and associated facilities who subscribe to this Agreement ("Transmission Owners" or "TOs", which expression includes their permitted successors and assigns).

This Agreement is made with reference to the following facts:

(i) The Legislature of the State of California enacted Assembly Bill 1890 ("AB 1890") that addressed the restructuring of the California electric industry in order to increase competition in the provision of electricity.

(ii) AB 1890 provides the means for transforming the regulatory framework of California's electric industry in ways to meet the objectives of the law.

(iii) In order to create a new market structure, AB 1890 establishes an Independent System Operator ("ISO") with centralized control of a state-wide transmission grid charged with ensuring the efficient use and reliable operation of the transmission system.

(iv) AB 1890 states that it is the intention of the California Legislature that California transmission owners commit control of their transmission facilities to the ISO with the assurances provided in the law that the financial interests of such TOs will be protected.

(v) Each TO: (1) owns, operates, and maintains transmission lines and associated facilities; and/or (2) has Entitlements to use certain transmission lines and associated facilities, with responsibilities attached thereto.

(vi) Each TO, upon satisfying the criteria for becoming a Participating TO under Section 2.2 of this Agreement, will transfer to the ISO Operational Control of certain transmission lines and associated facilities which are to be incorporated by the ISO into the ISO Controlled Grid for the purpose of allowing them to be controlled as part of an integrated Control Area.

(vii) Each Participating TO will continue to own and maintain its transmission lines and associated facilities, if any, and will retain its Entitlements, if any, and associated responsibilities.

(viii) The ISO intends to provide to each Participating TO access to the ISO Controlled Grid while exercising its Operational Control for the benefit of all Market Participants by providing non-discriminatory transmission access, Congestion Management, grid security, and Control Area services.

(ix) Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), and Southern California Edison Company ("Edison") (each a Participating TO) are entering into this agreement transferring Operational Control of their transmission facilities in reliance upon California Public Utilities Code Sections 367, 368, 375, 376 and 379 enacted as part of AB 1890 which contain assurances and schedules with respect to recovery of transition costs.

(x) The Parties desire to enter into this Agreement in order to establish the terms and conditions under which TOs will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities.

In consideration of the above and the covenants and mutual agreements set forth herein, and intending to be legally bound, the Parties agree as follows:

1. DEFINITIONS

Capitalized terms in this Agreement have the meaning set out in the Master Definitions Supplement set out in Appendix D. No subsequent amendment to the Master Definitions Supplement shall affect the interpretation of this Agreement unless made pursuant to Section 26.11.

2. PARTICIPATION IN THIS AGREEMENT

2.1. Transmission Owners:

2.1.1 **Initial Transmission Owners.** The following entities are subscribing to this Agreement as of the date hereof for the purpose of applying to become Participating TOs in accordance with Section 2.2:

- i. Pacific Gas and Electric Company;
- ii. San Diego Gas & Electric Company; and
- iii. Southern California Edison Company.

2.1.2 Right to Become a Party.

After this Agreement takes effect, any other owner of or holder of Entitlements to transmission lines and facilities connected to the ISO Controlled Grid may apply to the ISO under Section 2.2 to become a Participating TO and become a Party to this Agreement.

2.2. Applications for Participating TO Status; Eligibility Criteria.

2.2.1 **Application Procedures.** All applications under this Section 2.2 shall be made in accordance with the procedures adopted by the ISO from time to time and shall be accompanied by:

- (i) a description of the transmission lines and associated facilities that the applicant intends to place under the ISO's Operational Control;
- (ii) in relation to any such transmission lines and associated facilities that the applicant does not own, a copy of each document setting out the applicant's Entitlements to such lines and facilities;
- (iii) a statement of any Encumbrances to which any of the transmission lines and associated facilities to be placed under the ISO's Operational Control are subject, together with any documents creating such Encumbrances and any dispatch protocols to give effect to them, as the ISO may require;
- (iv) a statement that the applicant intends to place under the ISO's Operational Control all of the transmission lines and associated facilities referred to in Section 4.1 that it owns or, subject to the treatment of Existing Contracts under Sections 2.4.3 and 2.4.4 of the ISO Tariff, to which it has Entitlements and its reasons for believing that certain lines and facilities do not form part of the applicant's transmission network pursuant to Sections 4.1.1.i and 4.1.1.ii;
- (v) a statement of any Local Reliability Criteria to be included as part of the Applicable Reliability Criteria;

- (vi) a description of the applicant's current maintenance practices;
- (vii) a list of any temporary waivers that the applicant wishes the ISO to grant under Section 5.1.6 and the period for which it requires them;
- (viii) a copy of the applicant's proposed TO Tariff, if any, must be filed;
- (ix) address and contact names to which notices under this Agreement may be sent pursuant to Section 26.1;
- (x) any other information that the ISO may reasonably require in order to evaluate the applicant's ability to comply with its obligations as a Participating TO; and
- (xi) details of the applicant's Settlement Account.

2.2.2 Notice of Application. The ISO shall require the applicant to deliver to each existing Participating TO a copy of each application under this Section 2.2 and each amendment, together with all supporting documentation and to provide the public with reasonable details of its application and each amendment through WEnet or the ISO internet website. The ISO shall not grant an application for Participating TO status until it has given each other Party and the public sixty (60) days to comment on the original application and thirty (30) days to comment on each amendment.

2.2.3 Determination of Eligibility. Subject to Section 2.2.4, the ISO shall permit a Party who has submitted an application under this Section 2.2 to become a Participating TO if, after considering all comments received from other Parties and third parties, the ISO determines that:

- i. the applicant's transmission lines and associated facilities that are to be placed under the ISO's Operational Control can be incorporated into the ISO Controlled Grid without any material adverse impact on its reliability;
- ii. incorporating such transmission lines and associated facilities into the ISO Controlled Grid will not put the ISO in breach of Applicable Reliability Criteria and its obligations as a member of WSCC;
- iii. objections by the ISO under Section 4.1.3 shall have been withdrawn or determined by the ISO Governing Board to be invalid;
- iv. all applicable regulatory approvals of the applicant's TO Tariff have been obtained; and
- v. the applicant is capable of performing its obligations under this Agreement.

Objections under Section 4.1.3 relating solely to a portion of a TO's Facilities shall not prevent the TO from becoming a Participating TO while the objections are being resolved.

2.2.4 Challenges to Eligibility. The ISO shall permit a Party to become a Participating TO pending the outcome of ISO ADR Procedures challenging whether or not the applicant satisfies the criteria set out in Section 2.2.3 if the ISO determines that the applicant satisfies those criteria unless otherwise ordered by FERC.

2.2.5 Becoming a Participating TO. A Party whose application under this Section 2.2 has been accepted shall become a Participating TO with effect from the date when its TO Tariff takes effect, either as a result of acceptance by FERC or by action of a Local Regulatory Authority, whichever is appropriate. The TO Tariff of each Participating TO shall be posted on WEnet or the ISO internet website.

2.2.6 Procedures and Charges. The ISO shall adopt fair and non-discriminatory procedures for processing applications under this Section 2.2. The ISO shall publish its procedures for processing applications under this Section 2.2 on WEnet or on the ISO internet website and shall furnish a copy of such procedures to FERC. Applicants shall pay all costs incurred by the ISO in processing their

applications. The ISO will furnish applicants, upon request, an itemized bill for the costs of processing their application.

2.3. Tax Exempt Debt.

2.3.1 Municipal Tax-Exempt TOs. In the event a Municipal Tax-Exempt TO executes this Agreement in reliance upon this Section 2.3, it shall provide written notice thereof to the ISO. Notwithstanding any other provision to the contrary herein, except for this Section 2.3, no other provisions of this Agreement shall become effective with respect to a Municipal Tax-Exempt TO until such Municipal Tax-Exempt TO's nationally recognized bond counsel renders an opinion, generally of the type regarded as unqualified in the bond market, that participation in the ISO Controlled Grid in accordance with this Agreement will not adversely affect the tax-exempt status of any Municipal Tax-Exempt Debt issued by, or for the benefit of, the Municipal Tax-Exempt TO. A Municipal Tax-Exempt TO shall promptly seek, in good faith, to obtain such unqualified opinion from its bond counsel at the earliest opportunity. Upon receipt of such unqualified opinion, a Municipal Tax-Exempt TO shall provide a copy of the opinion to the ISO and all other provisions of this Agreement shall become effective with respect to such Municipal Tax-Exempt TO as of the date thereof. If the Municipal Tax-Exempt TO is unable to provide to the ISO such unqualified opinion within one year of the execution of this Agreement by the Municipal Tax-Exempt TO, without further act, deed or notice this Agreement shall be deemed to be void *ab initio* with respect to such Municipal Tax-Exempt TO.

2.3.2 Acceptable Encumbrances. A Transmission Owner that has issued Local Furnishing Bonds may become a Participating TO under Section 2.2 even though covenants or restrictions applicable to the Transmission Owner's Local Furnishing Bonds require the ISO's Operational Control to be exercised subject to Encumbrances, provided that such Encumbrances do not materially impair the ISO's ability to meet its obligations under the ISO Tariff or the Transmission Owner's ability to comply with the TO Tariff.

2.3.3 Savings Clause. Nothing in this Agreement shall compel any Participating TO or Municipal Tax-Exempt TO which has issued Tax-Exempt Debt to violate restrictions applicable to transmission facilities financed with Tax-Exempt Debt or contractual restrictions and covenants regarding use of transmission facilities.

3. EFFECTIVE DATE, TERM AND WITHDRAWAL

3.1. Effective Date.

This Agreement shall become effective as of the latest of:

- i. the date that it is signed by the ISO and the Transmission Owners referred to in Section 2.1.1;
- ii. the date the CPUC or its delegate declares to be the start date for direct access pursuant to CPUC Decision 97-12-131; and
- iii. the date when this Agreement is accepted for filing and made effective by the FERC.

3.2. Term.

This Agreement shall remain in full force and effect until terminated: (1) by operation of law or (2) the withdrawal of all Participating TOs pursuant to Section 3.3 or Section 4.4.1.

3.3. Withdrawal.

3.3.1 **Notice.** Subject to Section 3.3.3, any Participating TO may withdraw from this Agreement on two years' prior written notice to the other Parties. In addition, Western Area Power Administration ("Western") may be required to withdraw as a Participating TO pursuant to Section 26.14.1.

3.3.2 **Sale.** Subject to Section 3.3.3, any Participating TO may withdraw from this Agreement if that Participating TO sells or otherwise disposes of all of the transmission facilities and Entitlements that the Participating TO placed under the ISO's Operational Control, subject to the requirements of Section 4.4.

3.3.3 **Conditions of Withdrawal.** Any withdrawal from this Agreement pursuant to Section 3.3.1 or Section 3.3.2 shall be contingent upon the withdrawing party obtaining any necessary regulatory approvals for such withdrawal. The withdrawing Participating TO shall make a good faith effort to ensure that its withdrawal does not unduly impair the ISO's ability to meet its Operational Control responsibilities as to the facilities remaining within the ISO Controlled Grid.

3.3.4 **Publication of Withdrawal Notices.** The ISO shall inform the public through WEnet or the ISO internet website of all notices received under this Section 3.3.

3.4 Withdrawal Due to Adverse Tax Action.

3.4.1 **Right to Withdraw Due To Adverse Tax Action.** Subject to Sections 3.4.2 through 3.4.4, in the event an Adverse Tax Action Determination identifies an Impending Adverse Tax Action or an Actual Adverse Tax Action, a Tax Exempt Participating TO may exercise its right to Withdraw for Tax Reasons. The right to Withdraw for Tax Reasons, in accordance with the provisions of this Section 3.4, shall not be subject to any approval by the ISO, the FERC or any other Party.

3.4.2 Adverse Tax Action Determination.

3.4.2.1 A Tax Exempt Participating TO shall provide to all other Parties written notice of an Adverse Tax Action Determination and a copy of the Tax Exempt Participating TO's (or its joint action agency's) nationally recognized bond counsel's opinion or an IRS determination supporting such Adverse Tax Action Determination. Such written notice shall be provided promptly under the circumstances, but in no event more than 15 working days from the date of receipt of such documents.

3.4.2.2 The Adverse Tax Action Determination shall include (i) the actual or projected date of the Actual Adverse Tax Action and (ii) a description of the transmission lines, associated facilities or Entitlements that were financed in whole or in part with proceeds of the Tax Exempt Debt that is the subject of such Adverse Tax Action Determination. A Tax Exempt Participating TO shall promptly notify all other Parties in writing in the event the actual or projected date of the Actual Adverse Tax Action changes. The Tax Exempt Participating TO's determination of the actual or projected date of the Actual Adverse Tax Action shall be binding upon all Parties.

3.4.2.3 Any transmission lines, associated facilities or Entitlements of the Tax Exempt Participating TO not identified in both the Adverse Tax Action Determination and the written notice of Withdrawal for Tax Reasons shall remain under the ISO's Operational Control.

3.4.3 **Withdrawal Due to Impending Adverse Tax Action.** A Tax Exempt Participating TO may Withdraw for Tax Reasons prior to an Actual Adverse Tax Action if such Tax Exempt Participating TO provides prior written notice of its Withdrawal for Tax Reasons to all other Parties as required in Sections 3.4.3(i) through 3.4.3(iv).

i. In the event the date of the Adverse Tax Action Determination is seven months or more from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO that exercises its right to Withdraw for Tax Reasons shall provide prior written notice of its

Withdrawal for Tax Reasons to all other Parties at least six months in advance of the projected date of the Actual Adverse Tax Action.

ii. In the event the date of the Adverse Tax Action Determination is less than seven months but more than two months from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO that exercises its right to Withdraw for Tax Reasons shall provide prior written notice of its Withdrawal for Tax Reasons to all other Parties at least 30 days in advance of the projected date of the Actual Adverse Tax Action.

iii. In the event the date of the Adverse Tax Action Determination is between two months and one month from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO that exercises its right to Withdraw for Tax Reasons shall provide prior written notice of its Withdrawal for Tax Reasons to all other Parties at least 15 days in advance of the projected date of the Actual Adverse Tax Action.

iv. In the event the date of the Adverse Tax Action Determination is less than one month from the projected date of the Actual Adverse Tax Action, then a Tax Exempt Participating TO shall have up to 15 days following the date of the Adverse Tax Action Determination to exercise its right to Withdraw for Tax Reasons, and if so exercised shall provide no later than one day thereafter written notice of its Withdrawal for Tax Reasons to all other Parties.

v. With respect to Sections 3.4.3(i) through 3.4.3(iii), upon receipt by the ISO of a notice to Withdraw for Tax Reasons, the ISO shall promptly begin working with the applicable Tax Exempt Participating TO to relinquish the ISO's Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO, provided that such Operational Control must be relinquished by the ISO no later than five days prior to the projected date of the Actual Adverse Tax Action. With respect to Section 3.4.3(iv), (1) if the notice of Withdrawal for Tax Reasons is received by the ISO at least six days prior to the projected date of the Actual Adverse Tax Action, Operational Control over the affected transmission lines, associated facilities or Entitlements must be relinquished by the ISO to such Tax Exempt Participating TO no later than five days prior to the projected date of the Actual Adverse Tax Action, or (2) if the notice of Withdrawal for Tax Reasons is received by the ISO any time after six days prior to the projected date of the Actual Adverse Tax Action, the ISO shall on the next day relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO.

3.4.4 Withdrawal Due to Actual Adverse Tax Action. In addition to the foregoing, upon the occurrence of an Actual Adverse Tax Action, the affected Tax Exempt Participating TO may immediately Withdraw for Tax Reasons. The Tax Exempt Participating TO shall have up to 15 days from the date of the Adverse Tax Action Determination with respect to an Actual Adverse Tax Action to exercise its right to Withdraw for Tax Reasons. If the Tax Exempt Participating TO determines to exercise its right to Withdraw for Tax Reasons, upon receipt of the notice of Withdrawal for Tax Reasons, the ISO shall immediately relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO.

3.4.5 Alternate Date To Relinquish Operational Control. Notwithstanding anything to the contrary in this Section 3.4, the ISO and a Tax Exempt Participating TO who has provided a notice of Withdrawal for Tax Reasons may mutually agree in writing to an alternate date that the ISO shall relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO. If the ISO or a Tax Exempt Participating TO who has provided a notice of Withdrawal for Tax Reasons desires an alternate date from the date provided in Sections 3.4.3(i) through 3.4.3(v)(1) for the ISO to relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements to such Tax Exempt Participating TO, such party promptly shall give written notice to the other, and each agrees to negotiate in good faith, for a reasonable

period of time, to determine whether or not they can reach mutual agreement for such an alternate date; provided, however, such good faith negotiations are not required to be conducted during the five days preceding the date provided in Sections 3.4.3(i) through 3.4.3(v)(1) for the ISO to relinquish Operational Control over the affected transmission lines, associated facilities or Entitlements.

3.4.6 Procedures to Relinquish Operational Control. The ISO shall implement a procedure jointly developed by all Parties to relinquish Operational Control over the affected transmission lines, associated facilities, or Entitlements as provided in this Section 3.4.

3.4.7 Right to Rescind Notice of Withdrawal for Tax Reasons. At any time up to two days prior to the ISO's relinquishment to the Tax Exempt Participating TO of Operational Control over the affected transmission lines, associated facilities or Entitlements, a Tax Exempt Participating TO may rescind its notice of Withdrawal for Tax Reasons by providing written notice thereof to all other Parties, and such notice shall be effective upon receipt by the ISO.

3.4.8 Amendment of Agreement. Following the relinquishment by the ISO of Operational Control of facilities, recognizing Entitlements of a non-public utility in accordance with this Section 3.4, the ISO promptly shall prepare the necessary changes to this Agreement and to the ISO Tariff (if any), make a filing with FERC pursuant to Section 205 of the FPA, and take whatever other regulatory action, if any, that is required to properly reflect the Withdrawal for Tax Reasons.

3.4.9 Provision of Information by ISO. To assist Tax Exempt Participating TOs in identifying at the earliest opportunity Impending Adverse Tax Actions or Actual Adverse Tax Actions, the ISO promptly shall provide to Participating TOs any non-confidential information regarding any ISO plans, actions or operating protocols that the ISO believes might adversely affect the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO.

3.4.10 Publication of Notices. The ISO shall inform the public through WEnet or the ISO internet website of all notices received under this Section 3.4.

4. Transfer of Operational Control

4.1. TO Facilities and Rights Provided to the ISO.

4.1.1 ISO Controlled Grid. Subject to Section 4.1.2 and the treatment of Existing Contracts under Sections 2.4.3 and 2.4.4 of the ISO Tariff and subject to the applicable interconnection, integration, exchange, operating, joint ownership and joint participation agreements, each Participating TO shall place under the ISO's Operational Control the transmission lines and associated facilities forming part of the transmission network that it owns or to which it has Entitlements, except that Western shall only be required to place under the ISO's Operational Control the transmission lines and associated facilities that it owns or to which it has Entitlements as set forth in Appendix A (Western). The Initial Transmission Owners identified in Section 2.1.1 shall be deemed to have placed such transmission lines and associated facilities under the ISO's Operational Control as of the date the CPUC or its delegate declares to be the start date for direct access pursuant to CPUC Decisions 97-12-131 and 98-01-053. Any transmission lines or associated facilities that the ISO determines not to be necessary to fulfill the ISO's responsibilities under the ISO Tariff in accordance with Section 4.1.3 of this Agreement shall not be treated as part of a Participating TO's network for the purposes of this Section 4.1. The ISO shall recognize the rights and obligations of owners of jointly-owned facilities which are placed under the ISO's Operational Control by one or more but not all of the joint owners. The ISO shall, in exercise of Operational Control transferred to it, ensure that the operating obligations, as specified by the Participating TO pursuant to Section 6.4.2 of this Agreement, for the contracts referenced in Appendix B are performed. Any other terms of such contracts shall not be the

responsibility of the ISO. The following transmission lines and associated facilities are also deemed not to form part of a Participating TO's transmission network:

- i. directly assignable radial lines and associated facilities interconnecting generation (other than those facilities which may be identified from time to time interconnecting ISO Controlled Grid Critical Protective Systems or Generators contracted to provide Black Start or Voltage Support) and
- ii. lines and associated facilities classified as "local distribution" facilities in accordance with FERC's applicable technical and functional test and other facilities excluded consistent with FERC established criteria for determining facilities subject to ISO Operational Control.

4.1.2 Transfer of Facilities by Local Furnishing Participating TOs. This Section 4.1.2 is applicable only to the enlargement of transmission capacity by Local Furnishing Participating TOs. The ISO shall not require a Local Furnishing Participating TO to enlarge its transmission capacity except pursuant to an order under Section 211 of the FPA directing the Local Furnishing Participating TO to enlarge its transmission capacity as necessary to provide transmission service as determined pursuant to Section 3.2.9 of the ISO Tariff. If an application under Section 211 of the FPA is filed by an eligible entity (or the ISO acting as its agent), the Local Furnishing Participating TO shall thereafter, within 10 days of receiving a copy of the Section 211 application, waive its right to a request for service under Section 213(a) of the FPA and to the issuance of a proposed order under Section 212(c) of the FPA. Upon receipt of a final order from FERC under Section 211 of the FPA that is no longer subject to rehearing or appeal, such Local Furnishing Participating TO shall enlarge its transmission capacity to comply with that FERC order and shall transfer to the ISO Operational Control over its expanded transmission facilities in accordance with this Section 4.

4.1.3 Refusal of Facilities. The ISO may refuse to exercise Operational Control over certain of an applicant's transmission lines, associated facilities or Entitlements if it determines during the processing of an application under Section 2.2 that any one or more of the following conditions exist:

- i. The transmission lines, associated facilities or Entitlements do not meet or do not permit the ISO to meet the Applicable Reliability Criteria and the applicant fails to give the ISO a written undertaking to take all good faith actions necessary to ensure that those transmission lines, facilities or Entitlements, as the case may be, meet the Applicable Reliability Criteria within a reasonable period from the date of the applicant's application under Section 2.2 as determined by the ISO.
- ii. The transmission lines, associated facilities or Entitlements are subject to Encumbrances that unduly impair the ISO's ability to exercise its Operational Control over them in accordance with the ISO Tariff and the applicant fails to give the ISO a written undertaking to negotiate in good faith to the extent permitted by the applicable contract the removal of the Encumbrances identified by the ISO which preclude it from using unused capacity on the relevant transmission lines. If the applicant provides such written undertaking but is unable to negotiate the removal of such Encumbrances to the extent required by the ISO, the ADR Procedure shall be used to resolve any disputes between the ISO and the applicant. For this purpose, Non-Participating TOs may utilize ISO ADR procedures on a voluntary basis.
- iii. The transmission lines, associated facilities and Entitlements are located in a Control Area outside of California, are operated under the direction of another Control Area or independent system operator, and cannot be integrated into the ISO Controlled Grid due to technical considerations.

If the ISO refuses to accept any of an applicant's transmission lines, facilities or Entitlements, then that applicant shall have the right to notify the ISO within a reasonable period from being notified of such refusal that it will not proceed with its application under Section 2.2.

4.1.4 Facilities Initially Placed Under the ISO's Operational Control. The transmission lines, associated facilities and Entitlements which each Participating TO places under the ISO's Operational Control on the date that this Agreement takes effect with respect to it shall be identified in Appendix A.

4.1.5 Warranties. Each Participating TO warrants that as of the date on which it becomes a Participating TO pursuant to Section 2.2.5:

i. the transmission lines and associated facilities that it is placing under the ISO's Operational Control and the Entitlements that it is making available for the ISO's use are correctly identified in Appendix A (as amended in accordance with this Agreement); that the Participating TO has all of the necessary rights and authority to place such transmission lines and associated facilities under the ISO's Operational Control subject to the terms and conditions of all agreements governing the use of such transmission lines and associated facilities; and that the Participating TO has the necessary rights and authority to transfer the use of such Entitlements to the ISO subject to the terms and conditions of all agreements governing the use of such Entitlements;

ii. the transmission lines and associated facilities that it is placing under the ISO's Operational Control are not subject to any Encumbrances except as disclosed in Appendix B (as amended in accordance with this Agreement);

iii. the transmission lines and associated facilities that it is placing under the ISO's Operational Control meet the Applicable Reliability Criteria (ARC) for the relevant Participating TO except as disclosed in writing to the ISO. As to the Local Reliability Criteria component of ARC, each Participating TO has provided the ISO with such information required to identify such Participating TO's Local Reliability Criteria.

4.2. The ISO Register.

4.2.1 Register of Facilities Subject to ISO Operational Control. The ISO shall maintain a register (the "ISO Register") of all transmission lines, associated facilities and Entitlements that are for the time being subject to the ISO's Operational Control. The ISO Register shall also indicate those facilities over which the ISO has asserted temporary control pursuant to Section 4.5.2 and whether or not the ISO has commenced proceedings under Section 203 of the FPA in relation to them.

4.2.2 Contents. The ISO Register shall disclose in relation to each transmission line and associated facility subject to the ISO's Operational Control:

i. the identity of the Participating TO responsible for its operation and maintenance and its owner(s) (if other than the Participating TO);

ii. the date on which the ISO assumed Operational Control over it and, in the case of transmission lines and associated facilities over which it has asserted temporary Operational Control, the date on which it relinquished Operational Control over it;

iii. the date of any change in the identity of the Participating TO responsible for its operation and maintenance or in the identity of its owner; and

iv. its applicable ratings.

4.2.3 Updates. In order to keep the ISO Register current, each Participating TO shall submit an ISO Register change for each addition or removal of a transmission line or associated facility or Entitlement from the ISO's Operational Control or any change in a transmission line or associated facility's ownership, rating or the identity of the responsible Participating TO. The ISO shall review each ISO Register change for accuracy and to assure that all requirements of this Agreement have been met. If the ISO determines that a submitted ISO Register change is accurate and meets all the requirements of this Agreement, the ISO will modify the ISO Register to incorporate such change by the end of the next Business Day. The ISO may determine that an ISO Register change cannot be implemented due to (a) lack of clarity or necessary information, or (b) conflict between the revised rating and applicable contractual, regulatory or legal requirements including operating considerations, or other conflict with the terms of this Agreement. In such event, the ISO promptly will communicate to the Participating TO the reason that the ISO cannot implement the ISO Register change and will work with the Participating TO in an attempt to resolve promptly the concerns leading to the ISO's refusal to implement an ISO Register change. The ISO consent required with respect to a sale, assignment, release, transfer or other disposition of transmission lines, associated facilities or Entitlements as provided in Section 4.4 hereof shall not be withheld by the ISO as a result of an ISO determination that an ISO Register change cannot be implemented pursuant to this Section 4.2.3.

4.2.4 Publication. The ISO shall make the ISO Register information for a given Participating TO available to that same Participating TO on WEnet or a secure ISO-maintained internet website. The ISO will provide a copy of the ISO Register information to other entities that can demonstrate a legitimate need for the information in accordance with screening procedures posted on the ISO Home Page and filed with FERC.

4.2.5 Duty to Maintain Records. The ISO shall maintain the ISO Register in a form that conveniently shows the entities responsible for operating, maintaining and controlling the transmission lines and associated facilities forming part of the ISO Controlled Grid at any time and the periods during which they were so responsible.

4.3. Rights and Responsibilities of Participating TOs.

Each Participating TO shall retain its benefits of ownership and its rights and responsibilities in relation to the transmission lines and associated facilities placed under the ISO's Operational Control except as otherwise provided in this Agreement. Participating TOs shall be responsible for operating and maintaining those lines and facilities in accordance with this Agreement, the Applicable Reliability Criteria, the Operating Procedures and other criteria, ISO Protocols, procedures and directions of the ISO issued or given in accordance with this Agreement. Rights and responsibilities that have not been transferred to the ISO as operating obligations under Section 4.1.1 of this Agreement remain with the Participating TO. This Agreement shall have no effect on the remedies for breach or non-performance available to parties to existing interconnection, integration, exchange, operating joint ownership and joint participation agreements.

4.4. Sale or Disposal of Transmission Facilities or Entitlements.

4.4.1 Sale or Disposition.

4.4.1.1 No Participating TO shall sell or otherwise dispose of any lines or associated facilities forming part of the ISO Controlled Grid without the ISO's prior written consent, which consent shall not be unreasonably withheld.

4.4.1.2 As a condition to the sale or other disposition of any lines or associated facilities forming part of the ISO Controlled Grid to an entity that is not a Participating TO, the Participating TO shall require the transferee to assume in writing all of the Participating TO's obligations under this

Agreement (but without necessarily requiring it to become a Participating TO for the purposes of the ISO Tariff or a TO Tariff).

4.4.1.3 Any subsequent sale or other disposition by a transferee referred to in Section 4.4.1.2 shall be subject to this Section 4.4.1.

4.4.1.4 A transferee referred to in Section 4.4.1.2 that does not become a Participating TO shall have the same rights and responsibilities regarding withdrawal that a Participating TO has under Sections 3.3.1 and 3.3.3.

4.4.2 **Entitlements.** No Participating TO shall sell, assign, release, or transfer any Entitlements that have been placed under the ISO's Operational Control without the ISO's prior written consent, which consent shall not be unreasonably withheld, provided that such written consent is not required for such release or transfer to another Participating TO who is not in any material respect in breach of its obligations under this Agreement and who has not given notice of its intention to withdraw from this Agreement.

4.4.3 **Encumbrances.** No Participating TO shall create any new Encumbrance or (except as permitted by Sections 2.4.3 and 2.4.4 of the ISO Tariff) extend the term of an existing Encumbrance over any lines or associated facilities forming part of its transmission network (as determined in accordance with Section 4.1.1) without the ISO's prior written consent. The ISO shall give its consent to the creation or extension of an Encumbrance within thirty (30) days after receiving a written request for its consent disclosing in reasonable detail the nature of and reasons for the proposed change unless the ISO reasonably determines that the change is inconsistent with the Participating TO's obligations under the ISO Tariff or the TO Tariff or that the change may materially impair the ISO's ability to exercise Operational Control over the relevant lines or facilities or may reduce the reliability of the ISO Controlled Grid. Exercise of rights under an Existing Contract shall not be deemed to create a new Encumbrance for the purposes of this Section 4.4.3.

4.5. Procedure for Designating ISO Controlled Grid Facilities.

4.5.1 **Additional Facilities.** If the ISO determines that it requires Operational Control over additional transmission lines and associated facilities not then constituting part of the ISO Controlled Grid in order to fulfill its responsibilities in relation to the ISO Controlled Grid then the ISO shall apply to FERC pursuant to Section 203 of the Federal Power Act, and shall make all other regulatory filings necessary to obtain approval for such change of control and shall serve a copy of all such applications on the affected Participating TO and the owner of such lines and facilities (if other than the Participating TO). In the event that a Party invokes the dispute resolution provisions identified in Section 15 with respect to the transfer of Operational Control over a facility, such facility shall not be transferred while the dispute resolution process is pending except pursuant to Section 4.5.2.

4.5.2 **Temporary Operational Control.** The ISO may exercise temporary Operational Control over any transmission lines or associated facilities of a Participating TO (including lines and facilities to which the Participating TO has sufficient Entitlement to permit the ISO to exercise Operational Control over them) that do not then form part of the ISO Controlled Grid:

i. in order to prevent or remedy an imminent System Emergency;

ii. on reasonable notice, for a period not exceeding ninety (90) days, in order to determine whether exercising Operational Control over the relevant lines and facilities will assist the ISO to meet Applicable Reliability Criteria or to fulfill its Control Area responsibilities under the ISO Tariff; or

iii. subject to any contrary order of FERC, pending the resolution of the procedures referenced in Section 4.5.1.

4.5.3 Return of Control of Facilities. Control of facilities over which the ISO has assumed temporary Operational Control will be returned to the appropriate Participating TO when the conditions set forth in Section 4.5.2 no longer require the ISO to assume such temporary control.

4.5.4 Transmission Expansion Projects. Any transmission expansion projects carried out pursuant to Section 3.2 of the ISO Tariff shall be subject to the ISO's Operational Control from the date that it goes into service or after such period as the ISO deems to be reasonably necessary for the ISO to integrate the project into the ISO Controlled Grid.

4.6. TOs Control Centers.

4.6.1 ISO's Right to Occupy Participating TOs Control Centers. From the ISO Operations Date until the date when, in the reasonable opinion of the ISO, the ISO Control Center is established in accordance with Section 2.3.1.1 of the ISO Tariff, each Participating TO shall allow the ISO access to and such rights to occupy the Participating TO's existing control centers as the ISO reasonably requires for the purposes of exercising Operational Control of the ISO Controlled Grid.

4.6.2 Confidentiality. The parties to this Agreement shall implement Section 4.6.1 in conformity with the confidentiality requirements of Section 26.3.

4.7. Termination of ISO's Operational Control.

4.7.1 Release from ISO's Operational Control. Subject to Section 4.7.2, the ISO may relinquish its Operational Control over any transmission lines and associated facilities constituting part of the ISO Controlled Grid if, after consulting the Participating TOs owning or having Entitlements to them, the ISO determines that it no longer requires to exercise Operational Control over them in order to meet its Control Area responsibilities and they constitute:

- i. directly assignable radial lines and associated facilities interconnecting Generation (other than lines and facilities interconnecting ISO Controlled Grid Critical Protective Systems or Generators contracted to provide Black Start or Voltage Support);
- ii. lines and associated facilities which, by reason of changes in the configuration of the ISO Controlled Grid, should be classified as "local distribution" facilities in accordance with FERC's applicable technical and functional test, or should otherwise be excluded from the facilities subject to ISO Operational Control consistent with FERC established criteria; or
- iii. lines and associated facilities which are to be retired from service in accordance with Good Utility Practice.

4.7.2 Procedures. Before relinquishing Operational Control over any transmission lines or associated facilities pursuant to section 4.7.1, the ISO shall inform the public through WEnet and the ISO internet website of its intention to do so and of the basis for its determination pursuant to Section 4.7.1. The ISO shall give interested parties not less than 45 days within which to submit written objections to the proposed removal of such lines or facilities from the ISO's Operational Control. If the ISO cannot resolve any timely objections to the satisfaction of the objecting parties and the Participating TOs owning or having Entitlements to the lines and facilities, such parties, Participating TOs, or the ISO may refer any disputes for resolution pursuant to the ISO ADR Procedures in Section 13 of the ISO Tariff. Alternatively, the ISO may apply to FERC for its approval of the ISO's proposal.

4.7.3 Duty to Update ISO Register. The ISO shall promptly record any change in Operational Control pursuant to this Section 4.7 in the ISO Register in accordance with Section 4.2.3.

5. INDEPENDENT SYSTEM OPERATOR

5.1. Control Area Operator.

5.1.1 Membership of WSCC and RTGs. The ISO shall be the designated Control Area operator for the ISO Controlled Grid and shall be a member of the WSCC and the relevant Regional Transmission Groups (RTGs) in that capacity. No Party shall take any position before the WSCC or an RTG that is inconsistent with a binding decision reached through the dispute resolution process referenced in Section 15, provided that the scope of the decision was no greater than the issues set forth in the statement of claims published by the ISO pursuant to Section 13.2.2 of the ISO Tariff.

5.1.2 Operational Control. The ISO shall exercise Operational Control over the ISO Controlled Grid for the purpose of:

- i. providing a framework for the efficient transmission of electricity across the ISO Controlled Grid in accordance with the ISO Tariff;
- ii. securing compliance with all Applicable Reliability Criteria;
- iii. scheduling transactions for Market Participants to provide open and non-discriminatory access to the ISO Controlled Grid in accordance with the ISO Tariff;
- iv. relieving Congestion; and
- v. to the extent provided in this Agreement, assisting Market Participants to comply with other operating criteria, contractual obligations and legal requirements binding on them.

5.1.3 Duty of Care. The ISO shall have the exclusive right and responsibility to exercise Operational Control over the ISO Controlled Grid, subject to and in accordance with Applicable Reliability Criteria and the operating criteria established by the NRC operating licenses for nuclear generating units as provided in Appendix E pursuant to Section 6.4.2. The ISO shall take proper care to ensure the safety of personnel and the general public. It shall act in accordance with Good Utility Practice, applicable law, Existing Contracts, the ISO Tariff and the Operating Procedures. The ISO shall not direct a Participating TO to take any action which would require a Participating TO to operate its transmission facilities in excess of their applicable rating as established or modified from time to time by the Participating TO pursuant to Section 6.4 except in a System Emergency where such a direction is consistent with Applicable Reliability Criteria.

5.1.4 Operating Procedures. The ISO shall, in consultation with the Participating TOs and other Market Participants, promulgate Operating Procedures governing its exercise of Operational Control over the ISO Controlled Grid in accordance with this Agreement. The ISO shall provide copies of the Operating Procedures and all amendments, revisions and updates to the Participating TOs and shall make them available to the public through WENet or the ISO internet website.

5.1.5 Applicable Reliability Criteria. The ISO shall, in consultation with Participating TOs and other Market Participants, develop and promulgate Applicable Reliability Criteria for the ISO Controlled Grid, which shall be in compliance with the reliability standards promulgated by NERC, WSCC, Local Reliability Criteria and NRC grid criteria related to operating licenses for nuclear generating units. The ISO shall provide copies of the Applicable Reliability Criteria and all amendments, revisions and updates to the Participating TOs and shall make them available to the public through WENet or the ISO internet website.

5.1.6 Waivers. The ISO may grant to any Participating TO whose transmission facilities do not meet the Applicable Reliability Criteria when it becomes a party to this Agreement such waivers from the Applicable Reliability Criteria as the Participating TO reasonably requires to prevent it from being in breach of this Agreement while it brings its transmission facilities into full compliance. Such waivers shall be effective for such period as the ISO shall determine. A Participating TO who has been granted

a waiver made under this Section 5.1.6 shall bring its transmission facilities into compliance with the Applicable Reliability Criteria before the expiration of the relevant waivers and in any event as soon as reasonably practical.

5.1.7 Operational Protocols. In exercising Operational Control over the ISO Controlled Grid, the ISO shall comply with the operational protocols to be provided in accordance with Section 6.4.2, as they may be amended from time to time to take account of the removal and relaxation of any Encumbrances to which the ISO Controlled Grid is subject. Participating TOs whose transmission lines and associated facilities are subject to Encumbrances shall make all reasonable efforts to remove or relax those Encumbrances in order to permit the operational protocols to be amended in such manner as the ISO may reasonably require, to the extent permitted by Existing Contracts and applicable interconnection, integration, exchange, operating, joint ownership and joint participation agreements.

5.1.8 System Emergencies. In the event of a System Emergency, the ISO shall have the authority and responsibility to take all actions necessary and shall direct the restoration of the ISO Controlled Grid to service following any interruption associated with a System Emergency. The ISO shall also have the authority and responsibility, consistent with Section 4 and Section 9, to act to prevent System Emergencies. Actions and directions by the ISO pursuant to this Section 5.1.8 shall be consistent with Section 5.1.3, Duty of Care.

5.1.9 Reporting Criteria. The ISO shall comply with the reporting requirements of the WSCC, NERC, NRC and regulatory bodies having jurisdiction over it. Participating TOs shall provide the ISO with information that the ISO may require to meet this obligation.

5.2. Monitoring.

5.2.1 System Requirements. The ISO shall establish reasonable metering, monitoring, and data collection standards and requirements for the ISO Controlled Grid, consistent with WSCC and NERC standards.

5.2.2 System Conditions. The ISO shall monitor and observe real time system conditions throughout the ISO Controlled Grid, as well as key facilities in other areas of the WSCC region.

5.2.3 Power Management System. The ISO shall install a computerized Power Management System (PMS) to monitor transmission facilities in the ISO Controlled Grid. A Participating TO may at its own expense and for its own internal management purposes install a read only PMS workstation that will provide the Participating TO with the same displays the ISO uses to monitor the Participating TO's transmission facilities.

5.2.4 Data. Unless otherwise mutually agreed, the ISO shall obtain real time monitoring data for the facilities listed in the ISO Register from the Participating TOs through transfers to the ISO of data available from the Energy Management Systems (EMS) of the Participating TOs.

5.3. Coordination Role.

The ISO shall perform a WSCC security coordinator function as designated by the WSCC. As such, the ISO shall have all necessary powers as described in this Agreement in relation to Participating TOs to meet the applicable NERC and WSCC requirements for security coordinators. The ISO shall assume this responsibility concurrent with the commencement of ISO Operational Control.

5.4. Public Information.

5.4.1 WEnet. The ISO shall develop a public information board ("WEnet" or ISO internet website) for the ISO Controlled Grid in accordance with the provisions in Section 6 of the ISO Tariff.

5.4.2 **Access to ISO Information.** The ISO shall permit the general public to inspect and copy other information in its possession, other than information to be kept confidential under Section 26.3, provided that the costs of providing documents for inspection, including any copying costs, shall be borne by the requester.

5.5. Costs

The ISO shall not implement any reliability requirements, operating requirements or performance standards that would impose increased costs on a Participating TO without giving due consideration to whether the benefits of such requirements or standards are sufficient to justify such increased costs. In any proceeding concerning the cost recovery by a Participating TO of capital and operation and maintenance costs incurred to comply with ISO-imposed reliability requirements, operating requirements, or performance standards, the ISO shall, at the request of the Participating TO, provide specific information regarding the nature of, and need for, the ISO-imposed requirements or standards to enable the Participating TO to use this information in support of cost recovery through rates and tariffs.

6. PARTICIPATING TRANSMISSION OWNERS

6.1. Physical Operation of Facilities.

6.1.1 **Operation.** Each Participating TO shall have the exclusive right and responsibility to operate and maintain its transmission facilities and associated switch gear and auxiliary equipment (including facilities that it operates under Entitlements).

6.1.2 **ISO Operating Orders.** Each Participating TO shall operate its transmission facilities in compliance with ISO Protocols, the Operating Procedures (including emergency procedures in the event of communications failure) and ISO's operating orders unless the health or safety of personnel or the general public would be endangered. Proper implementation of an ISO operating order by a Participating TO shall be deemed prudent. In the event an ISO order would risk damage to facilities, and if time permits, a Participating TO shall inform the ISO of any such risk and seek confirmation of the relevant ISO order.

6.1.3 **Duty of Care.** In operating and maintaining its transmission facilities, each Participating TO shall take proper care to ensure the safety of personnel and the general public. It shall act in accordance with Good Utility Practice, applicable law, ISO Protocols, the Operating Procedures and the Applicable Reliability Criteria.

6.1.4 **Outages.** Each Participating TO shall obtain approval from the ISO before taking out of service and returning to service any facility identified pursuant to Section 4.2.1 in the ISO Register, except in cases involving immediate hazard to the safety of personnel and the general public or imminent damage to facilities where there is not time to contact the ISO. The Participating TO shall promptly notify the ISO of such situations.

6.1.5 **Return to Service.** After a System Emergency or Forced Outage, the Participating TO shall restore to service the transmission facilities under the ISO's Operational Control as soon as possible and in the priority order determined by the ISO. The ISO's Operating Procedures shall give priority to restoring offsite power to nuclear generating units, in accordance with criteria specified by the Participating TOs under the design basis and licensing requirements of the NRC licenses applicable to such nuclear units and any other Regulatory Must-Run Generation whose operation is critical for the protection of wildlife and the environment.

6.1.6 **Written Report.** Within a reasonable time, the Participating TO shall provide the ISO with a written report, consistent with Section 17, describing the circumstances and the reasons for any Forced Outage, including outages under Section 6.1.4.

6.2. Transmission Service.

6.2.1 Compliance with Tariffs. Participating TOs shall allow access to their transmission facilities (including any that are not for the time being under the ISO's Operational Control) only on the terms of the ISO Tariff and the TO Tariff.

6.2.2 Release of Scheduling Rights. When required by the ISO, a Participating TO shall release all of its scheduling rights over the transmission lines and associated facilities that are part of the ISO Controlled Grid to the extent such rights are established through Existing Contracts among or between Participating TOs, as provided in the ISO Tariff.

6.3. Other Responsibilities.

Each Participating TO shall inspect, maintain, repair, replace and maintain the rating and technical performance of its facilities under the ISO's Operational Control in accordance with the Applicable Reliability Criteria (subject to any waivers granted pursuant to Section 5.1.6) and the performance standards established under Section 14.

6.4. Technical Information and Protocols.

6.4.1 Information to be Provided. Each Participating TO shall provide to the ISO prior to the effective date of this Agreement, and in a format acceptable to the ISO:

- i. Technical specifications for any facilities under the ISO's Operational Control, as the ISO may require;
- ii. The applicable ratings of all transmission lines and associated facilities listed in Appendix A; and
- iii. A copy of each document creating an Entitlement or Encumbrance.

The Participating TO shall promptly notify the ISO in writing or mutually acceptable electronic format of any subsequent changes in such technical specifications, ratings, Entitlements or Encumbrances.

6.4.2 Protocols for Encumbered Facilities. A Party that is placing a transmission line or associated facility (including an Entitlement) that is subject to an Encumbrance under the Operational Control of the ISO shall develop protocols for its operation which shall: (1) reflect the rights the Party has in such facility, and (2) give effect to any Encumbrance on such facility. Such protocols shall be delivered to the ISO for review not less than ninety (90) days prior to the date on which the ISO is expected to assume Operational Control of any such facility. The ISO shall review each protocol and shall cooperate with the relevant Party to assure that operations pursuant to the protocol are feasible and that the protocol is consistent with the applicable rights and Encumbrances. To the extent such protocol is required to be filed at FERC, the relevant Transmission Owner shall file such protocol not less than sixty (60) days prior to the date on which the ISO is expected to assume Operational Control of the relevant facility. Protocols to implement the operating criteria established by the NRC operating licenses for nuclear generating units are provided in Appendix E.

6.5. EMS/SCADA System.

Each Participating TO shall operate and maintain its EMS/SCADA systems and shall allow the ISO access to the Participating TO's data from such systems relating to the facilities under the ISO's Operational Control. The ISO, at its own cost, may, if it considers it necessary for the purpose of carrying out its responsibilities under this Agreement, acquire, install and maintain additional monitoring equipment on any Participating TO's property.

6.6. Single Point Of Contact.

Each Participating TO shall provide the ISO with an appropriate single point of contact for the coordination of operations under this Agreement.

7. SYSTEM OPERATION AND MAINTENANCE

7.1. Scheduled Maintenance.

The Parties shall forecast and coordinate Maintenance Outage plans in accordance with Section 2.3.3 of the ISO Tariff.

7.2. Exercise of Contractual Rights.

In order to facilitate Maintenance Outage coordination of the ISO Controlled Grid by the ISO, each Participating TO shall, to the extent that the Participating TO has contractual rights to do so: (1) coordinate Maintenance Outages with Non-Participating Generators; and (2) exercise its contractual rights to require maintenance by Non-Participating Generators in each case in such manner as the ISO approves or requests. The requirements of this Section 7.2 shall not apply to any Non-Participating Generator with a rated capability of less than 50 MW.

7.3. Unscheduled Maintenance.

7.3.1 Notification. A Participating TO shall notify the ISO of any faults on the ISO Controlled Grid or any actual or anticipated Forced Outages as soon as it becomes aware of them, in accordance with Section 2.3.3 of the ISO Tariff.

7.3.2 Returns to Service. The Participating TO shall take all steps necessary, consistent with Good Utility Practice and in accordance with the ISO Tariff and ISO Protocols, to prevent Forced Outages and to return to operation, as soon as possible, any facility under the ISO's Operational Control that is the subject of a Forced Outage.

8. CRITICAL PROTECTIVE SYSTEMS THAT SUPPORT ISO CONTROLLED GRID OPERATIONS

8.1. Remedial Action Systems, Under Frequency Load Shedding, Under Voltage Load Shedding.

Each Participating TO shall coordinate its Critical Protective Systems with the ISO, other Transmission Owners, and Generators to ensure that its Remedial Action Schemes ("RAS"), Under Frequency Load Shedding ("UFLS"), and Under Voltage Load Shedding ("UVLS") schemes function on a coordinated and complementary basis in accordance with WSCC/NERC planning, reliability, and protection policies and standards. Participating TOs that are parties to contracts affecting RAS, UFLS, and UVLS schemes shall make reasonable efforts to amend those contracts in order to permit the RAS, UFLS, and UVLS schemes to be operated in accordance with WSCC/NERC planning, reliability, and protection policies and standards and the ISO Tariff.

Each Participating TO, in conjunction with the ISO, shall identify, describe, and provide to the ISO the functionality of all RAS for electric systems operating at 200 kV nominal voltage or higher and any other lower voltage lines that the ISO and Participating TO determine to be critical to the reliability of the ISO Controlled Grid. Each Participating TO shall provide to the ISO a description of the functionality of UFLS and UVLS schemes that protect the security and reliability of transmission facilities on the ISO Controlled Grid.

Each Participating TO shall maintain the design, functionality, and settings of its existing RAS, UFLS, and UVLS schemes. New or existing schemes that are functionally modified must be in accordance with WSCC/NERC planning, reliability, and protection policies and standards. Each Participating TO shall notify the ISO in advance of all RAS, UFLS, and UVLS schemes functionality

and setting changes that affect transmission facilities on the ISO Controlled Grid. Each Participating TO shall not disable or take clearances on RAS or UVLS schemes without the approval of the ISO through the Maintenance Outage and Forced Outage coordination process in accordance with the ISO Tariff. Clearances on UFLS may be taken without approval depending upon the armed load disabled as agreed to between the Participating TO and ISO and incorporated in the Operating Procedures.

The requirements of this Section 8.1 shall apply only to the transmission facilities that are part of the ISO Controlled Grid.

8.2. Protective Relay Systems.

Each Participating TO shall provide to the ISO protective relay system functional information necessary to perform system planning and operating analysis, and to operate transmission facilities on the ISO Controlled Grid in compliance with WSCC/NERC planning, reliability and protection policies and standards.

The requirements of this Section 8.2 shall apply only to the transmission facilities that are part of the ISO Controlled Grid.

8.3 Non-ISO Controlled Grid Critical Protective Systems.

Each Participating TO may alter the settings and functionality of protective relay systems and Remedial Action Schemes that have not been designated as ISO Controlled Grid Critical Protective Systems without the consent of the ISO, provided that such changes do not reduce the normal or emergency rating of a facility identified in the ISO Register. If the facility rating will be reduced, the Participating TO shall obtain approval of the ISO prior to making such changes. In addition, the Participating TO shall promptly report to the ISO any facility rating increases that result from any changes to its protective relay settings or Remedial Action Schemes.

9. SYSTEM EMERGENCIES

9.1. ISO Management of Emergencies.

The ISO shall manage a System Emergency pursuant to the provisions of Section 2.3.2 of the ISO Tariff. The ISO may carry out unannounced tests of System Emergency procedures pursuant to the ISO Tariff.

9.2. Management of Emergencies by Participating TOs.

9.2.1 ISO Orders. In the event of a System Emergency, the Participating TOs shall comply with all directions from the ISO regarding the management and alleviation of the System Emergency unless such compliance would impair the health or safety of personnel or the general public.

9.2.2 Communication. During a System Emergency, the ISO and Participating TOs shall communicate through their respective control centers, in accordance with the Operating Procedures.

9.3. System Emergency Reports: TO Obligations.

9.3.1 Records. Pursuant to Section 17, each Participating TO shall maintain appropriate records pertaining to a System Emergency.

9.3.2 Review. Each Participating TO shall cooperate with the ISO in the preparation of an Outage review pursuant to Section 2.3 of the ISO Tariff and Section 17 of this Agreement.

9.4. Sanctions.

In the event of a major Outage that affects at least 10 percent of the customers of an entity providing local distribution service, the ISO may order a Participating TO to pay appropriate sanctions, as filed with and approved by FERC in accordance with Section 12.3, if the ISO finds that the operation and maintenance practices of the Participating TO, with respect to its transmission lines and associated facilities that it has placed under the ISO's Operational Control, prolonged the response time or was responsible for the Outage.

10. ISO CONTROLLED GRID ACCESS AND INTERCONNECTION

10.1. ISO Controlled Grid Access and Services.

10.1.1 **Access.** The ISO shall respond to requests from the Participating TOs and other Market Participants for access to the ISO Controlled Grid. All Participating TOs who have Eligible Customers connected to their transmission or distribution facilities that do not form part of the ISO Controlled Grid shall ensure open and non-discriminatory access to those facilities for those Eligible Customers through the implementation of an open access tariff, provided that a Participating TO shall only be required to ensure open access to those facilities for End-Use Customers to the extent it is required by applicable law to do so or pursuant to a voluntary offer to do so.

10.2. Interconnection.

10.2.1 **Obligation to Interconnect.** The Parties shall be obligated to allow interconnection to the ISO Controlled Grid in a non-discriminatory manner, subject to the conditions specified in this Section 10 and the applicable legal requirements.

10.2.2 **Standards.** All Interconnections shall be designed and built in accordance with Good Utility Practice, all Applicable Reliability Criteria, and applicable statutes and regulations.

10.2.3 **System Upgrades.** A Participating TO shall be entitled to require a entity requesting Interconnection to pay for all necessary system reliability upgrades on its side of the Interconnection and on the ISO Controlled Grid, as well as for all required studies, inspection and testing, to the extent permitted by FERC policy. The entity requesting Interconnection shall be required to execute an Interconnection Agreement in accordance with the ISO Tariff and the TO Tariff as applicable, provided that the terms of the ISO Tariff shall govern to the extent there is any inconsistency between the ISO Tariff and the TO Tariff, and must comply with all of their provisions, including provisions related to creditworthiness and payment for Facility Studies.

10.2.4 A Local Furnishing Participating TO shall not be obligated to construct or expand interconnection facilities or system upgrades unless and until the conditions stated in Section 4.1.2 hereof have been satisfied.

10.3. Interconnections Responsibilities.

10.3.1 Applicability. The provisions of this Section 10.3 shall apply only to those facilities over which a Participating TO has legal authority to effectuate proposed interconnections to the ISO Controlled Grid. Where a Participating TO does not have the legal authority to compel interconnection, the Participating TO's obligations with respect to interconnections shall be as set forth in its Commission approved TO Tariff which shall contain an obligation for the Participating TO, at a minimum, to submit or assist in the submission of, expansion and/or interconnection requests from third parties to the appropriate bodies of a project pursuant to the individual project agreements to the full extent allowed by such agreements and the applicable laws and regulations.

10.3.2 Technical Standards. Each Participating TO shall develop technical standards for the design, construction, inspection, and testing applicable to proposed Interconnections of Load and/or Generation Unit and apparatus to that part of the ISO Controlled Grid Facilities owned by the Participating TO. Such standards shall be consistent with Applicable Reliability Criteria and shall be developed in consultation with the ISO. The Participating TO shall periodically review and revise its criteria to ensure compliance with Applicable Reliability Criteria.

10.3.3 Review of Participating TO Technical Standards. Participating TOs shall provide the ISO with copies of their technical standards for Interconnection developed pursuant to Section 10.3.2 of this Agreement and all amendments so that the ISO can satisfy itself as to their compliance with the Applicable Reliability Criteria. The ISO shall develop consistent Interconnection standards across the ISO Controlled Grid, to the extent possible given the circumstances of each Participating TO, in consultation with Participating TOs. Any differences in Interconnection standards shall be addressed through negotiations and dispute resolution proceedings, as set forth in the ISO Tariff, between the ISO and the Participating TO.

10.3.4 Notice. A list of the Interconnection standards and procedures developed by each Participating TO pursuant to Section 10.3.2, including any revisions, shall be made available to the public through the information board (e.g. WEnet or ISO internet website). In addition, the posting will provide information on how to obtain the Interconnection standards and procedures. The Participating TO shall provide these standards to any party, upon request.

10.3.5 Interconnection. Each Participating TO and the ISO shall process Interconnection requests in accordance with the ISO Tariff and the TO Tariff as applicable, provided that the terms of the ISO Tariff shall govern to the extent there is any inconsistency between the ISO Tariff and the TO Tariff. Any differences in the procedures for interconnection contained in the ISO Tariff and the TO Tariff shall be addressed through negotiations and dispute resolution procedures, as set forth in the ISO Tariff, between the ISO and the Participating TO.

10.3.6 Acceptance of Interconnection Facilities. The Participating TO shall perform all necessary site inspections, review all relevant equipment tests, and ensure that all necessary agreements have been fully executed prior to accepting Interconnection facilities for operation.

10.3.7 Collection of Payments. The Participating TO shall collect all payments owed under any System Impact Study Agreement, Facility Study Agreement or other agreement entered into pursuant to this Section 10.3 or the provisions of the ISO Tariff and its TO Tariff as applicable relating to Interconnection.

10.3.8 On-Site Inspections. The ISO may at its own expense accompany a Participating TO during on-site inspections and tests of Interconnections or, by pre-arrangement, may itself inspect Interconnections or perform its own additional inspections and tests.

10.4 Joint Responsibilities.

The Parties shall share with the ISO relevant information about Interconnection requests and coordinate their activities to ensure that all Interconnection requests are processed in a timely, non-discriminatory fashion and that all Interconnections meet the operational and reliability criteria applicable to the ISO Controlled Grid. Subject to Section 26.3 of this Agreement, the ISO shall pass on such information to any Parties who require it to carry out their responsibilities under this Agreement.

11. EXPANSION OF TRANSMISSION FACILITIES

The provisions of Section 3.2 of the ISO Tariff will apply to any expansion or reinforcement of the ISO Controlled Grid affecting the transmission facilities of the Participating TOs placed under the Operational Control of the ISO.

12. USE AND ADMINISTRATION OF THE ISO CONTROLLED GRID

12.1. USE OF THE ISO CONTROLLED GRID.

Except as provided in Section 13, use of the ISO Controlled Grid by the Participating TOs and other Market Participants shall be in accordance with the rates, terms, and conditions established in the ISO Tariff and the Participating TO's Tariff. Pursuant to Section 2.1.2 of the ISO Tariff transmission service shall be provided only to direct access and wholesale customers eligible under state and federal law.

12.2. Administration.

Each Participating TO transfers authority to the ISO to administer the terms and conditions for access to the ISO Controlled Grid and to collect, among other things, Congestion Management revenues, and Wheeling-Through and Wheeling-Out revenues.

12.3. Incentives and Penalty Revenues.

The ISO, in consultation with the Participating TOs, shall develop standards and a mechanism for paying to and collecting from Participating TOs incentives and penalties that may be assessed by the ISO. Such standards and mechanism shall be filed with FERC and shall become effective upon acceptance by FERC.

13. EXISTING AGREEMENTS

The provisions of Sections 2.4.3 and 2.4.4 of the ISO Tariff will apply to the treatment of transmission facilities of a Participating TO under the Operational Control of the ISO which are subject to transmission service rights under Existing Contracts. In addition, the ISO will honor the operating obligations as specified by the Participating TO, pursuant to Section 6.4.2 of this Agreement, including any provision of interconnection, integration, exchange, operating, joint ownership and joint participation agreements, when operating the ISO Controlled Grid.

14. MAINTENANCE STANDARDS

14.1. ISO Determination of Standards.

The ISO shall adopt, in consultation with the Participating TOs through the Maintenance Coordination Committee, standards for the maintenance, inspection, repair, and replacement of transmission facilities under its Operational Control in accordance with Appendix C. These standards,

which shall be performance-based or prescriptive or both, will provide for high quality, safe, and reliable service and shall take into account costs, local geography and weather, the Applicable Reliability Criteria, national electric industry practice, sound engineering judgment and experience.

14.2. Existing Standards.

Until such time as the ISO adopts standards pursuant to Section 14.1, the ISO shall measure the performance of Participating TOs in relation to the maintenance, inspection, repair and replacement of transmission facilities by their existing standards. Each Participating TO shall provide the ISO with such information as the ISO shall require to identify such Participating TO's existing maintenance standards and measure its performance against the relevant standards.

14.3. Availability Formula.

14.3.1 Availability Measure. The ISO performance-based standards shall be based on the availability measures described in Section 4 of Appendix C of this Agreement.

14.3.2 Excluded Events. Scheduled Approved Maintenance Outages and certain Forced Outages will be excluded pursuant to Section 4.2.3 of Appendix C of this Agreement from the calculation of the availability measure.

14.3.3 Availability Measure Target. The Maintenance Coordination Committee and each Participating TO shall jointly develop for the Participating TO an availability measure target, which may be defined by a range. The target will be based on prior Participating TO performance developed in accordance with Section 4 of Appendix C of this Agreement and national benchmarks.

14.3.4 Calculation of Availability Measure. The availability measure shall be calculated annually by the Participating TO and reported to the ISO for evaluation of the Participating TO's compliance with the availability measure target. This calculation will determine the availability measure in accordance with Section 4 of Appendix C of this Agreement.

14.3.5 Compliance with Availability Measure Target. The ISO and the Participating TO may track the availability measure on a more frequent basis (e.g., quarterly, monthly), but the annual calculation shall be the sole basis for determining the Participating TO's compliance with its availability measure target.

14.3.6 Public Record. The Participating TO's annual availability measure calculation and the associated availability measure data shall be made available to the public.

14.4. Revisions to Standards.

The ISO shall periodically review with the Participating TOs the standards and incentives implemented pursuant to this Section 14 and, through the Maintenance Coordination Committee process, shall modify these standards and incentives as necessary.

14.5. Incentives and Penalties.

The ISO shall, subject to regulatory approval, develop incentive programs which reward or impose sanctions on Participating TOs by reference to their availability measure and the extent to which the availability performance imposes demonstrable costs or results in demonstrable benefits for Market Participants.

15. DISPUTE RESOLUTION

In the event any dispute regarding the terms and conditions of this Agreement is not settled, the Parties shall follow the ISO ADR Procedure set forth in Section 13 of the ISO Tariff. The specific references in this Agreement to alternative dispute resolution procedures shall not be interpreted to limit the Parties' rights and obligations to invoke dispute resolution procedures pursuant to this Section 15.

16. BILLING AND PAYMENT

16.1 Application of ISO Tariff

The ISO and Participating TOs shall comply with the billing and payment provisions set forth in Section 11 of the ISO Tariff.

16.2 Refund Obligation

Each Participating TO, whether or not it is subject to the rate jurisdiction of the FERC under Section 205 and Section 206 of the Federal Power Act, shall make all refunds, adjustments to its Transmission Revenue Requirement, and adjustments to its tariff and do all other things required of a participating TO to implement any FERC order related to the ISO tariff, including any ferc order that requires the ISO to make payment adjustments or pay refunds to, or receive prior period overpayments from, any participating TO. All such refunds and adjustments shall be made, and all other actions taken, in accordance with the ISO Tariff, unless the applicable FERC order requires otherwise.

17. RECORDS AND INFORMATION SHARING

17.1. Records Relevant to Operation of ISO Controlled Grid.

The ISO shall keep such records as may be necessary for the efficient operation of the ISO Controlled Grid and shall make appropriate records available to a Participating TO, upon request. The ISO shall maintain for not less than five (5) years: (1) a record of its operating orders and (2) a record of the contents of, and changes to, the ISO Register.

17.2. Participating TO Records and Information Sharing.

17.2.1 Existing Standards. Each Participating TO shall provide to the ISO in a format and at the time to be established by the ISO in coordination with the Participating TO, the Participating TO's standards for inspection, maintenance, repair, and replacement of its facilities under the ISO's Operational Control in effect as of the date it executes this Agreement.

17.2.2 Records. Each Participating TO shall provide and maintain current data, records, and drawings describing the physical and electrical properties of the facilities under the ISO's Operational Control and shall maintain records of all inspections, maintenance, replacement, and repairs performed on such facilities, which records shall be shared with the ISO under reasonable guidelines and procedures to be specified by the ISO.

17.2.3 Required Reports. Pursuant to this Agreement and the provisions of the ISO Tariff, each Participating TO shall provide to the ISO timely information, notices, or reports regarding matters of mutual concern, including:

- i. System Emergencies, Forced Outages and other incidents affecting the ISO Controlled Grid;

- ii. Maintenance Outage requests, including yearly forecasts required by Section 2.3.3.5 of the ISO Tariff;
- iii. System Planning Studies, including studies prepared in connection with Interconnections or any transmission facility enhancement or expansion; and
- iv. Compliance with the inspection, maintenance, repair, and replacement standards established under Section 14.

17.2.4 Other Reports. The ISO may, upon reasonable notice to the Participating TO, request that the Participating TO provide the ISO with such information or reports necessary for the operation of the ISO Controlled Grid. The Participating TO shall make all such information or reports available to the ISO within a reasonable time and in a form to be specified by the ISO.

17.2.5 Other Market Participant Information. At the request of the ISO, a Participating TO shall provide the ISO with non-confidential information obtained by the Participating TO from other Market Participants pursuant to contracts between the Participating TO and such other Market Participants. Such requests shall be limited to information that is reasonably necessary for the operation of the ISO Controlled Grid.

17.3. ISO System Studies and Operating Procedures.

17.3.1 System Studies and Grid Stability Analyses. The ISO, in coordination with Participating TOs, shall perform system operating studies or grid stability analyses to evaluate forecasted changes in grid conditions that could affect its ability to ensure compliance with the Applicable Reliability Criteria. The results and reports from such studies shall be exchanged between the ISO and the Participating TOs. Study results and conclusions shall generally be assessed annually, and shall be updated as necessary, based on changing grid and local area conditions.

17.3.2 Grid Conditions Affecting Regulations, Permits and Licenses. The ISO shall promulgate and maintain Operating Procedures to ensure that impaired or potentially degraded grid conditions are assessed and immediately communicated to the Participating TOs for operability determinations required by applicable regulations, permits or licenses, such as NRC operating licenses for nuclear generating units.

17.4. Significant Incident.

17.4.1 Risk of Significant Incident. Any Party shall timely notify all other Parties if it becomes aware of the risk of significant incident, including extreme temperatures, storms, floods, fires, earthquakes, earth slides, sabotage, civil unrest, equipment outage limitations, etc., that affect the ISO Controlled Grid. The Parties shall provide information that the reporting Party reasonably deems appropriate and necessary for the other Parties to prepare for the occurrence, in accordance with Good Utility Practice.

17.4.2 Occurrence of Significant Incident. Any Party shall timely notify all other Parties if it becomes aware that a significant incident affecting the ISO Controlled Grid has occurred. Subsequent to notification, each Party shall make available to the ISO all relevant data related to the occurrence of the significant incident. Such data shall be sufficient to accommodate any reporting or analysis necessary for the Parties to meet their obligations under this Agreement.

17.5. Review of Information and Record-Related Policies.

The ISO shall review the requirements of this Section 17 annually and shall, consistent with reliability and regulatory needs, seek to standardize reasonable record keeping, reporting, and information sharing requirements.

18. GRANTING RIGHTS-OF-ACCESS TO FACILITIES

18.1. Equipment Installation.

In order to meet its obligations under this Agreement, a Party that owns, rents, or leases equipment (the equipment owner) may require installation of such equipment on property owned by another Party (the property owner), provided that the property is being used for an electric utility purpose and that the property owner shall not be required to do so if it would thereby be prevented from performing its own obligations or exercising its rights under this Agreement.

18.1.1 Free Access. The property owner shall grant to the equipment owner free of charge reasonable installation rights and rights of access to accommodate equipment inspection, repair, upgrading, or removal for the purposes of this Agreement, subject to the property owner's reasonable safety, operational, and future expansion needs.

18.1.2 Notice. The equipment owner (whether ISO or Participating TO) shall provide reasonable notice to the property owner when requesting access for site assessment, coordinating equipment installation, or other relevant purposes.

18.1.3 Removal of Installed Equipment. Following reasonable notice, the equipment owner shall be required, at its own expense, to remove or relocate equipment, at the request of the property owner, provided that the equipment owner shall not be required to do so if it would thereby be prevented from performing its obligations or exercising its rights under this Agreement.

18.1.4 Costs. The equipment owner shall repair at its own expense any property damage it causes in exercising its rights and shall reimburse the property owner for any other costs that it is required to incur to accommodate the equipment owner's exercise of its rights under this Section 18.1.

18.2. Rights to Assets.

The Parties shall not interfere with each other's assets, without prior agreement.

18.3. Inspection of Facilities.

In order to meet their respective obligations under this Agreement, any Party may view or inspect facilities owned by another Party. Provided that reasonable notice is given, a Party shall not unreasonably deny access to relevant facilities for viewing or inspection by the requesting Party.

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20. TRAINING

20.1. Staffing and Training to Meet Obligations.

Each Party shall make its own arrangements for the engagement of all staff and labor necessary to perform its obligations hereunder and for their payment. Each Party shall employ (or cause to be employed) only persons who are appropriately qualified, skilled, and experienced in their respective trades or occupations. ISO employees and contractors shall abide by the ISO Code of Conduct contained in the ISO Bylaws and approved by FERC.

20.2. Technical Training.

The ISO and the Participating TOs shall respond to reasonable requests for support and provide relevant technical training to each other's employees to support the safe, reliable, and efficient operation of the ISO Controlled Grid and to comply with any NERC or WSCC operator certification or training requirements. Examples of such technical training include, but are not limited to: (1) the theory or operation of new or modified equipment (e.g., control systems, remedial action schemes, protective relays); (2) computer and applicator programs; and (3) ISO (or Participating TO) requirements. The Parties shall enter into agreements regarding the timing, term, locations, and cost allocation for the training.

21. OTHER SUPPORT SYSTEMS REQUIREMENTS

21.1. Related Systems.

The Parties shall each own, maintain, and operate equipment, other than those facilities described in the ISO Register, which is necessary to meet their specific obligations under this Agreement.

21.2. Lease or Rental of Equipment by the ISO.

Under certain circumstances, it may be prudent for the ISO to lease or rent equipment owned by a Participating TO, (e.g., EMS/SCADA, metering, telemetry, and communications systems), instead of installing its own equipment. In such case, the ISO and the Participating TO shall mutually determine whether the ISO shall lease or rent the Participating TO's equipment. The ISO and the Participating TO shall enter into a written agreement specifying all the terms and conditions governing the lease or rental, including its term, equipment specifications, maintenance, availability, liability, interference mitigation, and payment terms.

22. LIABILITY

22.1. Liability for Damages.

Except as provided for in Section 13.3.14 of the ISO Tariff and subject to Section 22.4 no Party to this Agreement shall be liable to any other Party for any losses, damages, claims, liability, costs or expenses (including legal expenses) arising from the performance or non-performance of its obligations under this Agreement except to the extent that its negligent performance of this Agreement (including intentional breach) results directly in physical damage to property owned, operated by or under the operational control of any of the other Parties or in the death or injury of any person.

22.2. Exclusion of Certain Types of Loss.

No Party shall be liable to any other party under any circumstances whatsoever for any consequential or indirect financial loss (including but not limited to loss of profit, loss of earnings or revenue, loss of use, loss of contract or loss of goodwill) resulting from physical damage to property for which a party may be liable under Section 22.1.

22.3. ISO's Insurance.

The ISO shall maintain insurance policies covering part or all of its liability under this Agreement with such insurance companies and containing such policy limits and deductible amounts as shall be determined by the ISO Governing Board from time to time. The ISO shall provide all Participating TOs with details of all insurance policies maintained by it pursuant to this Section 22 and shall have them named as additional insureds to the extent of their insurable interest.

22.4. Participating TOs Indemnity.

Each Participating TO shall indemnify the ISO and hold it harmless against all losses, damages, claims, liability, costs or expenses (including legal expenses) arising from third party claims due to any act or omission of that Participating TO except to the extent that they result from intentional wrongdoing or negligence on the part of the ISO or of its officers, directors or employees. The ISO shall give written notice of any third party claims against which it is entitled to be indemnified under this Section to the Participating TOs concerned promptly after becoming aware of them. The Participating TOs who have acknowledged their obligation to provide a full indemnity shall be entitled to control any litigation in relation to such third party claims (including settlement and other negotiations) and the ISO shall, subject to its right to be indemnified against any resulting costs, cooperate fully with the Participating TOs in defense of such claims.

23. UNCONTROLLABLE FORCES

23.1. Occurrences of Uncontrollable Forces.

An Uncontrollable Force means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, any curtailment, order, regulation, or restriction imposed by governmental, military or lawfully established civilian authorities or any other cause beyond a Party's reasonable control and without such Party's fault or negligence. No Party will be considered in default as to any obligation under this Agreement if prevented from fulfilling the obligation due to the occurrence of an Uncontrollable Force.

23.2. Obligations in the Event of an Uncontrollable Force.

In the event of the occurrence of an Uncontrollable Force, which prevents a Party from performing any of its obligations under this Agreement, such Party shall: (1) immediately notify the other Parties of such Uncontrollable Force with such notice to be confirmed in writing as soon as reasonably practicable; (2) not be entitled to suspend performance of its obligations under this Agreement to any greater extent or for any longer duration than is required by the Uncontrollable Force; (3) use its best efforts to mitigate the effects of such Uncontrollable Force, remedy its inability to perform, and resume full performance of its obligations hereunder; (4) keep the other Parties apprised of such efforts on a continual basis; and (5) provide written notice of the resumption of performance hereunder. Notwithstanding any of the foregoing, the settlement of any strike, lockout, or labor dispute constituting an Uncontrollable Force shall be within the sole discretion of the Party to this Agreement involved in such strike, lockout, or labor dispute and the requirement that a Party must use its best efforts to remedy the cause of the Uncontrollable Force and/or mitigate its effects and resume full performance hereunder shall not apply to strikes, lockouts, or labor disputes.

24. ASSIGNMENTS AND CONVEYANCES

No Party may assign its rights or transfer its obligations under this Agreement except, in the case of a Participating TO, pursuant to Section 4.4.1.

25. ISO ENFORCEMENT

In addition to its other rights and remedies under this Agreement, the ISO may if it sees fit initiate regulatory proceedings seeking the imposition of sanctions against any Participating TO who commits a material breach of its obligations under this Agreement.

26. MISCELLANEOUS

26.1. Notices.

Any notice, demand, or request in accordance with this Agreement, unless otherwise provided in this Agreement, shall be in writing and shall be deemed properly served, given, or made: (1) upon delivery if delivered in person; (2) five (5) days after deposit in the mail, if sent by first class United States mail, postage prepaid; (3) upon receipt of confirmation by return electronic facsimile if sent by facsimile; or (4) upon delivery if delivered by prepaid commercial courier service. Any Party may at any time, by notice to the other Parties, change the designation or address of the person specified to receive notice on its behalf in Appendix F. Such changes to Appendix F shall not constitute an amendment to this Agreement. Any notice of a routine character in connection with service under this Agreement or in connection with the operation of facilities shall be given in such a manner as the Parties may determine from time to time, unless otherwise provided in this Agreement.

26.2. Non-Waiver.

Any waiver at any time by any Party of its rights with respect to any default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not constitute or be deemed a waiver with respect to any subsequent default or other matter arising in connection with this Agreement. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not constitute or be deemed a waiver.

26.3. Confidentiality.

26.3.1 ISO. The ISO shall maintain the confidentiality of all of the documents, materials, data, or information ("Data") provided to it by any other Party that reflects or contains: (a) Data treated as confidential or commercially sensitive under the confidentiality provisions of Section 20.3 of the ISO Tariff; (b) critical energy infrastructure information, as defined in Section 388.113(c)(1) of the FERC's regulations (c) technical information and materials that constitute valuable, confidential, and proprietary information, know-how, and trade secrets belonging to a Party, including, but not limited to, information relating to drawings, maps, reports, specifications and records and/or software, data, computer models, and related documentation; or (d) Data that was previously public information but that was removed from public access in accordance with FERC's policy statement issued on October 11, 2001 in Docket No. PL02-1-000 in response to the September 11, 2001 terrorist attacks. In order to be subject to the confidentiality protections of this Section 26.3, Data provided by a Party to the ISO after January 1, 2005 which is to be accorded confidential treatment, as set forth above, shall be marked as "Confidential Data." Such a marking requirement, however, shall not be applicable to the Data provided by a Party to the ISO prior to January 1, 2005 so long as the Data qualifies for confidential treatment hereunder. Notwithstanding the foregoing, the ISO shall not keep confidential: (1) information that is explicitly subject to data exchange through WEnet or the ISO internet website pursuant to Section 6 of the ISO Tariff; (2) information that the ISO or the Party providing the information is required to disclose pursuant to this Agreement, the ISO Tariff, or applicable regulatory requirements (provided that the ISO shall comply with any applicable limits on such disclosure); or (3) the information becomes available to the public on a non-confidential basis (other than as a result of the ISO's breach of this Agreement).

26.3.2 Other Parties. No Party shall have a right hereunder to receive from the ISO or to review any documents, data or other information of another Party to the extent such documents, data or information are required to be kept confidential in accordance with Section 26.3.1 above, provided, however, that a Party may receive and review any composite documents, data, and other information that may be developed based upon such confidential documents, data, or information, if the composite document does not disclose any individual Party's confidential data or information.

26.3.3 Disclosure. Notwithstanding anything in this Section 26.3 to the contrary, if the ISO is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence pursuant to this Section 26.3, the ISO may disclose such information; provided, however, that as soon as the ISO learns of the disclosure requirement and prior to making such disclosure, the ISO shall notify the affected Party or Parties of the requirement and the terms thereof. The affected Party or Parties may, at their sole discretion and own costs, direct any challenge to or defense against the disclosure requirement and the ISO shall cooperate with such affected Party or Parties to the maximum extent practicable to minimize the disclosure of the information consistent with applicable law. The ISO shall cooperate with the affected Parties to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

26.4. Third Party Beneficiaries.

The Parties do not intend to create rights in, or to grant remedies to, any third party as a beneficiary of this Agreement or of any duty, covenant, obligation, or undertaking established hereunder.

26.5. Relationship of the Parties.

The covenants, obligations, rights, and liabilities of the Parties under this Agreement are intended to be several and not joint or collective, and nothing contained herein shall ever be construed to create an association, joint venture, trust, or partnership, or to impose a trust or partnership covenant, obligation, or liability on, or with regard to, any of the Parties. Each Party shall be individually responsible for its own covenants, obligations, and liabilities under this Agreement. No Party or group of Parties shall be under the control of or shall be deemed to control any other Party or Parties. No Party shall be the agent of or have the right or power to bind any other Party without its written consent, except as expressly provided for in this Agreement.

26.6. Titles.

The captions and headings in this Agreement are inserted solely to facilitate reference and shall have no bearing upon the interpretation of any of the terms and conditions of this Agreement.

26.7. Severability.

If any term, covenant, or condition of this Agreement or the application or effect of any such term, covenant, or condition is held invalid as to any person, entity, or circumstance, or is determined to be unjust, unreasonable, unlawful, imprudent, or otherwise not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant, or condition shall remain in force and effect to the maximum extent permitted by law, and all other terms, covenants, and conditions of this Agreement and their application shall not be affected thereby, but shall remain in force and effect and the parties shall be relieved of their obligations only to the extent necessary to eliminate such regulatory or other determination unless a court or governmental agency of competent jurisdiction holds that such provisions are not separable from all other provisions of this Agreement.

26.8. Preservation of Obligations.

Upon termination of this Agreement, all unsatisfied obligations of each Party shall be preserved until satisfied.

26.9. Governing Law.

This Agreement shall be interpreted, governed by and construed under the laws of the State of California, without regard to the principles of conflict of laws thereof, or the laws of the United States, as applicable, as if executed and to be performed wholly within the State of California.

26.10. Construction of Agreement.

Ambiguities or uncertainties in the wording of this Agreement shall not be construed for or against any Party, but shall be construed in a manner that most accurately reflects the purpose of this Agreement and the nature of the rights and obligations of the Parties with respect to the matter being construed.

26.11. Amendment.

This Agreement may be modified: (1) by mutual agreement of the Parties, subject to approval by FERC; (2) through the ISO ADR Procedure set forth in Section 13 of the ISO Tariff; or (3) upon issuance of an order by FERC.

26.12. Appendices Incorporated.

The several appendices to this Agreement, as may be revised from time to time, are attached to this Agreement and are incorporated by reference as if herein fully set forth.

26.13. Counterparts.

This Agreement may be executed in one or more counterparts, which may be executed at different times. Each counterpart, which shall include applicable individual Appendices A, B, C, D and E shall constitute an original but all such counterparts together shall constitute one and the same instrument.

26.14 Consistency with Federal Laws and Regulations

26.14.1 No Violation of Law. Nothing in this Agreement shall compel any Party to: (1) violate any federal statute or regulation; or (2) in the case of a federal agency, to exceed its statutory authority, as defined by any applicable federal statute, or regulation or order lawfully promulgated thereunder. No Party shall incur any liability by failing to comply with a provision of this Agreement that is inapplicable to it by reason of being inconsistent with any federal statute, or regulation or order lawfully promulgated thereunder; provided, however, that such Party shall use its best efforts to comply with this Agreement to the extent that applicable federal laws, and regulations and orders lawfully promulgated thereunder, permit it to do so.

If Western issues or revises any federal regulation or order with the intent or effect of limiting, impairing, or excusing any obligation of Western under this Agreement, then unless Western's action was expressly directed by Congress, any Party, by giving thirty days' advance written notice to the other Parties, may require Western to withdraw from this Agreement, notwithstanding any other notice period in Section 3.3.1. If such notice is given, the ISO and Western promptly shall meet to develop arrangements needed to comply with Western's obligation under Section 3.3.3 concerning non-impairment of ISO Operational Control responsibilities.

26.14.2 **Federal Entity Indemnity.** No provision of this Agreement shall require any Participating TO to give an indemnity to Western or for Western to give an indemnity to any Participating TO. If any provision of this Agreement requiring Western to give an indemnity to the ISO or the ISO to impose a sanction on Western is unenforceable against a federal entity, the affected Party shall submit to the Secretary of Energy or other appropriate Departmental Secretary a report of any circumstances that would, but for this provision, have rendered a federal entity liable to indemnify any person or incur a sanction and may request the Secretary of Energy or other appropriate Departmental Secretary to take such steps as are necessary to give effect to any provisions of this Agreement that are not enforceable against the federal entity.

26.14.3 **Recovery for Unenforceable Indemnity.** To the extent that a Party suffers any loss as a result of being unable to enforce any indemnity as a result of such enforcement being in violation of Section 26.14.2, it shall be entitled to seek recovery of such loss through its TO Tariff or through the ISO Tariff, as applicable.

27. SIGNATURE PAGE

CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION

California Independent System Operator Corporation has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 14th day of December, 2004 and thereby incorporates the following Appendices in this Agreement:

Appendices A

Appendices B

Appendix C

Appendix D

Appendices E

Appendix F

**CALIFORNIA INDEPENDENT SYSTEM
OPERATOR CORPORATION
151 Blue Ravine Road
Folsom, California 95630**

by: /s/ MARCI L. EDWARDS

**Marcie L. Edwards
Interim Chief Executive Officer**

28. SIGNATURE PAGE

PACIFIC GAS AND ELECTRIC COMPANY

Pacific Gas and Electric Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 20th day of December 2004 and thereby incorporates the following Appendices in this Agreement:

Appendix A (PG&E)

Appendix B (PG&E)

Appendix C

Appendix D

Appendix E (Diablo Canyon)

Appendix F

PACIFIC GAS AND ELECTRIC COMPANY
77 Beale Street
San Francisco, California 94105

by: /s/ **JEFFREY BUTLER**

Jeffrey Butler
Senior Vice President, Transmission &
Distribution

29. SIGNATURE PAGE

SAN DIEGO GAS & ELECTRIC COMPANY

San Diego Gas & Electric Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 22nd day of December, 2004 and thereby incorporates the following Appendices in this Agreement:

Appendix A (SDG&E)

Appendix B (SDG&E)

Appendix C

Appendix D

Appendix E (SONGS)

Appendix F

SAN DIEGO GAS & ELECTRIC COMPANY
8330 Century Park Court
San Diego, California 92123

by: /s/ **JAMES AVERY**

James Avery
Senior Vice President of San Diego Gas &
Electric

On September 7, 2004, the California Independent System Operator Corporation ("ISO") filed with the Federal Energy Regulatory Commission ("FERC") certain proposed revisions and additions to the Transmission Control Agreement and Appendices thereto (the "TCA Revisions"), and to the ISO Tariff (Dockets Nos. EL04-133-000; ER04-1198-000). San Diego Gas & Electric Company ("SDG&E") protested, in a filing made with the Commission on September 28, 2004 ("Protest"), a number of the TCA Revisions and the ISO Tariff revisions proposed by the ISO. On November 5, 2004, FERC issued a decision regarding the proposed revisions to the TCA and the ISO Tariff ("Order"). On December 6, 2004, the ISO made a compliance filing with respect to the Order ("Compliance Filing"). The ISO now proposes to file additional revisions to the TCA to reflect the addition of the City of Pasadena as a Participating Transmission Owner in the ISO. SDG&E's execution of the TCA is without any prejudice to or waiver of any argument or position taken by SDG&E in its Protest. SDG&E's execution of the TCA is not intended to accede to any provision or portion of the Order, the TCA revisions, the Compliance Filing or the associated ISO Tariff revisions. SDG&E is hereby reserving all of its rights with respect to the Order, the TCA Revisions, and the associated ISO Tariff revisions, including but not limited to all of the issues concerning the TCA (including any and all Appendices thereto) filed by the ISO on September 7, 2004, the membership of the Western Area Power Administration, Sierra Nevada Region ("WAPA") in the ISO, and the issues associated with WAPA's rights in and revenues associated with the Path 15 transmission upgrade.

30. SIGNATURE PAGE

SOUTHERN CALIFORNIA EDISON COMPANY

Southern California Edison Company has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 22nd day of December 2004 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Edison)

Appendix B (Edison)

Appendix C

Appendix D

Appendix E (SONGS)

Appendix F

SOUTHERN CALIFORNIA EDISON COMPANY
2244 Walnut Grove Avenue
Rosemead, California 91770

by: /s/ **RICHARD M. ROSENBLUM**

Richard M. Rosenblum
Senior Vice President, Transmission &
Distribution

On September 7, 2004, the California Independent System Operator Corporation ("ISO") filed with the Federal Energy Regulatory Commission ("FERC") certain proposed revisions and additions to the Transmission Control Agreement and Appendices thereto ("TCA Revisions"), and to the ISO Tariff (Dockets Nos. EL04-133-000; ER04-1198-000). Southern California Edison Company ("Edison") protested, in a filing made with the Commission on September 28, 2004 ("Protest"), a number of the TCA Revisions and the ISO Tariff revisions proposed by the ISO. On November 5, 2004, FERC issued a decision regarding the proposed revisions to the TCA and the ISO Tariff ("Order"). On December 6, 2004, Edison filed a request for rehearing and clarification of the Commission's Order ("Rehearing Petition"), and the ISO made a compliance filing with respect to the Order ("Compliance Filing"). The ISO now proposes to file additional revisions to the TCA to reflect the addition of the City of Pasadena as a Participating Transmission Owner in the ISO. Edison's execution of the TCA is without any prejudice to or waiver of any argument or position taken by Edison in its Protest or in its Rehearing Petition. Edison's execution of the TCA is not intended to and does not accede to any provision or portion of the Order, the TCA Revisions, the Compliance Filing or the associated ISO Tariff revisions. Edison is hereby reserving all of its rights with respect to the Order, the TCA Revisions, and the associated ISO Tariff revisions, including but not limited to, any and all of the issues concerning the TCA (including any and all Appendices thereto) filed by the ISO on September 7, 2004, the membership of the Western Area Power Administration, Sierra Nevada Region ("WAPA") in the ISO, and the issues associated with WAPA's rights in and revenues associated with the Path 15 transmission upgrade.

31. SIGNATURE PAGE

CITY OF VERNON

CITY OF VERNON has caused this Transmission Control Agreement to be executed by its duly authorized representative on this fifth day of December, 2000 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Vernon)

Appendix B (Vernon)

Appendix C

Appendix D

Appendix E

Appendix F

CITY OF VERNON

By: /s/ LEONIS C. MALBURG

LEONIS C. MALBURG, Mayor

ATTEST:

/s/ BRUCE V. MALKENHORST

BRUCE V. MALKENHORST, City Clerk

APPROVED AS TO FORM:

/s/ EDUARDO OLIVO

EDUARDO OLIVO, City Attorney

32. SIGNATURE PAGE

CITY OF ANAHEIM

CITY OF ANAHEIM has caused this Transmission Control Agreement to be executed by its duly authorized representative on this day of , 20 and thereby incorporates the following Appendices in this Agreement:

- Appendix A (Anaheim)
- Appendix B (Anaheim)
- Appendix C
- Appendix D
- Appendix F

CITY OF ANAHEIM

By: _____
Marcie L. Edwards
Public Utilities General Manager

ATTEST:

APPROVED AS TO FORM:

33. SIGNATURE PAGE

CITY OF AZUSA

CITY OF AZUSA has caused this Transmission Control Agreement to be executed by its duly authorized representative on this day of , 20 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Azusa)

Appendix B (Azusa)

Appendix C

Appendix D

Appendix F

CITY OF AZUSA

By:

Cristina C. Madrid
Mayor

34. SIGNATURE PAGE

CITY OF BANNING

CITY OF BANNING has caused this Transmission Control Agreement to be executed by its duly authorized representative on this _____ day of _____, 20____ and thereby incorporates the following Appendices in this Agreement:

Appendix A (Banning)

Appendix C

Appendix D

Appendix F

CITY OF BANNING

By: _____
John Hunt
Mayor

ATTEST:

APPROVED AS TO FORM:

35. SIGNATURE PAGE

CITY OF RIVERSIDE

CITY OF RIVERSIDE has caused this Transmission Control Agreement to be executed by its duly authorized representative on this _____ day of _____, 20____ and thereby incorporates the following Appendices in this Agreement:

- Appendix A (Riverside)
- Appendix B (Riverside)
- Appendix C
- Appendix D
- Appendix F

CITY OF RIVERSIDE
3900 Main Street, 4th Floor
Riverside, California 92522

By: _____
George A. Carvalho, City Manager

ATTEST:

City Clerk

APPROVED AS TO FORM:

Supervising Deputy City Attorney

36. SIGNATURE PAGE

TRANS-ELECT NTD PATH 15, LLC

TRANS-ELECT NTD PATH 15, LLC has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 21st day of December 2004 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Trans-Select)

Appendix C

Appendix D

Appendix F

Trans-Select NTD Path 15, LLC
1850 Centennial Park Drive
Suite 480
Reston, VA 20191

By:

ROBERT D. DICKERSON

Robert D. Dickerson
Executive Vice President

37. SIGNATURE PAGE

WESTERN AREA POWER ADMINISTRATION, SIERRA NEVADA REGION

WESTERN AREA POWER ADMINISTRATION, SIERRA NEVADA REGION has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 23rd day of December, 2004 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Western)

Appendix C

Appendix D

Appendix F

Western Area Power Administration, Sierra Nevada Region
Sierra Nevada Region
114 Parkshore Drive
Folsom, CA 95630-4710

By:

/s/ JAMES D. KESELBURG

James D. Keselburg
Regional Manager

37. SIGNATURE PAGE

CITY OF PASADENA

CITY OF PASADENA has caused this Transmission Control Agreement to be executed by its duly authorized representative on this 20th day of December, 2004 and thereby incorporates the following Appendices in this Agreement:

Appendix A (Pasadena)

Appendix C (Pasadena)

Appendix D

Appendix F

City of Pasadena Water and Power Department
150 S. Los Robles, Suite 200
Pasadena, CA 91101

By: CYNTHIA J. KURZ

Cynthia J. Kurtz
City Manager

ATTEST:

JANE L. RODRIGUEZ

Jane L. Rodriguez, CMC
City Clerk

TRANSMISSION CONTROL AGREEMENT

APPENDIX A

Facilities and Entitlements

**(The Diagrams of Transmission Lines and Associated
Facilities Placed Under the Control of the ISO
were submitted by the ISO on behalf of the Transmission Owners
on March 31, 1997—any modifications are
attached as follows)**

Modification of Appendix A1

Diagrams of Transmission Lines and Associated Facilities Placed Under the Control of the ISO

**(submitted by the ISO on behalf of Pacific Gas and Electric Company
Transmission Owner)**

The diagrams of transmission lines and associated facilities placed under the control of the ISO submitted by the ISO on behalf of PG&E on March 31, 1997 are amended as follows.

Item 1: Port of Oakland 115 kV Facilities

Operation Control of the transmission facilities, shown on operating diagram, East Bay Region (East Bay Division), Sheet No. 1, serving the Port of Oakland and Davis 115 kV (USN) is not to be transferred to the ISO. These are special facilities funded by and connected solely to a customer's substation and their operation is not necessary for control by the ISO pursuant to the specifications of Section 4.1.1 of the TCA.

As of the date of execution of the TCA, the California ISO and PG&E are discussing further modifications to the diagrams of transmission lines and facilities placed under the control of the ISO. A new version of the diagrams is to be filed with FERC prior to April 1, 1998. This subsequent version of the diagrams will reflect all modifications (including those described herein).

APPENDIX A2

List of Entitlements Being Placed under ISO Operational Control

(Includes only those where PG&E is a service rights-holder)

Ref. #	Entities	Contract / Rate Schedule #	Nature of Contract	Termination	Comments
1.	Pacific Power & Light, SCE, SDG&E	Transmission Use Agreement—PP&L Rate Schedule with FERC	Transmission	Upon 40 years beginning approx. 1968	
2.	SCE, SDG&E	California Power Pool—PG&E Rate Schedule FERC No. 27	Power pool	Terminated	5/6/97
3.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement—PG&E Rate Schedule FERC No. 38	Transmission	4/1/2007	Both entitlement and encumbrance.
4.	SCE, Montana Power, Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan—PG&E Rate Schedule FERC No. 183	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classify as an entitlement since loop flow is reduced or an encumbrance if PG&E is asked to cut.
5.	TANC	Coordinated Operations Agreement—PG&E Rate Schedule FERC No. 146	Interconnection, scheduling, transmission	1/1/2043	Both entitlement and encumbrance.
6.	WAPA	EHV Transmission Agreement—Contract No. 2947A—PG&E Rate Schedule FERC No. 35	Transmission	1/1/2005, but service to continue for a period and at charges to be agreed subject to FERC acceptance.	Both entitlement and encumbrance.
7.	Various—See Attachment A	Western Systems Power Pool Agreement—WSPP Rate Schedule FERC No. 1	Power sales, transmission	Upon WSPP expiration	Both entitlement and encumbrance.
8.	Vernon (City of)	Transmission Service Exchange Agreement—PG&E Rate Schedule FERC No. 148	Transmission	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for service on COTP

Supplement To PG&E's Appendix A

Notices Pursuant to Section 4.1.5

Pursuant to the Transmission Control Agreement Section 4.1.5 (iii), the transmission system(1) Pacific Gas and Electric Company (PG&E) is placing under the California Independent System Operator's Operational Control will meet the Applicable Reliability Criteria in 1998,(2) except (1) for the transmission facilities comprising Path 15, which do not meet the Western Systems Coordinating Council's (WSCC) Reliability Criteria for Transmission Planning with a simultaneous outage of the Los Banos-Gates and Los Banos-Midway 500 kV lines (for south-to-north power flow exceeding 2500 MW on Path 15),(3) and (2) with respect to potential problems identified in PG&E's annual assessment of its reliability performance in accordance with Applicable Reliability Criteria, performed with participation from the ISO and other stakeholders; as a result of this process, PG&E has been developing solutions to mitigate the identified potential problems and submitting them to the ISO for approval.

Pursuant to Section 4.1.5(i), PG&E does not believe that transfer of Operational Control is inconsistent with any of its franchise or right of way agreements to the extent that ISO Operational Control is implemented as part of PG&E utility service pursuant to AB 1890. However, PG&E can't warrant that these right of way or franchise agreements will provide necessary authority for ISO entry or physical use of such rights apart from PG&E's rights pursuant to its physical ownership and operation of transmission facilities.

-
- (1) Including upgrades and operational plans for the transmission lines and associated facilities.
 - (2) Based upon PG&E(1)s substation and system load forecasts for study year 1998, historically typical generation dispatch and the Applicable Reliability Criteria, including the current applicable WSCC Reliability Criteria for Transmission Planning issued in March 1997, the PG&E Local Reliability as stated in the 1997 PG&E Transmission Planning Handbook Criteria (submitted to the California ISO Transmission Planning, in writing, on October 20, 1997), and the NERC Reliability Performance Criteria in effect at the time PG&E was assessing its system (as of June 1, 1997). PG&E may not meet the WSCC(1)s Disturbance Performance level (0)D(1) (e.g. outage of three or more circuits on a right-of-way, an entire substation or an entire generating plant including switchyard), where the risk of such an outage occurring is considered very small and the costs of upgrades very high.
 - (3) The ISO will operate Path 15 so as to maintain system reliability. In accepting this notice from PG&E, the ISO agrees to work with PG&E and the WSCC to achieve a resolution respecting the WSCC long-term path rating limit for Path 15, consistent with WSCC requirements. Pending any revision to the WSCC long-term path rating limit for Path 15, the ISO will continue to operate Path 15 at the existing WSCC long-term path rating limit unless, in the judgment of the ISO:
 - (a) the operating limit must be reduced on a short-term (e.g., seasonal) basis to maintain system reliability, taking into account factors such as the WSCC guidelines, determination of credible outages and the Operating Capability Study Group (OCSG) study process; or
 - (b) the operating limit must be reduced on a real-time basis to maintain system reliability.

In determining whether the operating limit of Path 15 must be changed to maintain system reliability, the ISO shall, to the extent possible, work with the WSCC and the PTOs to reach consensus as to any new interim operating limit.

TRANSMISSION CONTROL AGREEMENT

APPENDIX B

Encumbrances

Issued by: Anthony Ivancovich, Senior Regulatory Counsel
Issued on: November 25, 2002

Effective: January 1, 2003

PG&E APPENDIX B

List of Encumbrances on Lines and Facilities, and Entitlements Being Placed under ISO Operational Control (per TCA Appendix A1 & A2) ¹

(Includes only those where PG&E is a service provider)

Abbreviations Used:

CDWR	= California Department of Water Resources
SCE	= Southern California Edison Company
SDG&E	= San Diego Gas & Electric Company
SMUD	= Sacramento Municipal Utility District
TANC	= Transmission Agency of Northern California
WAPA	= Western Area Power Administration

Ref. #	Entities	Contract/Rate Schedule #	Nature of Contract	Termination	Comments
1.	Bay Area Rapid Transit	Service Agreement Nos. 42 and 43 to FERC Electric Tariff, First Revised Volume No. 12	Network Integration Transmission Service Agreement and Network Operating Agreement — OAT	10/1/2016	
2.	CDWR	Comprehensive Agreement — PG&E Rate Schedule FERC No.77	Interconnection and transmission	12/31/2014	Transmission Related Losses
3.	CDWR	Etiwanda Power Plant Generation Exchange — PG&E Rate Schedule FERC No. 169	Power exchanges	Evergreen, or on 5 years notice	

1/ The treatment of current rights, including scheduling priorities, relating to the listed Encumbrances are set forth in the operating instructions submitted by the PTO in accordance with the ISO Tariff and the TCA.

Ref. #	Entities	Contract/Rate Schedule #	Nature of Contract	Termination	Comments
4.	CDWR	Extra High Voltage Transmission — PG&E Rate Schedule FERC No. 36	Transmission	1/1/2005	
5.	Dynegy Power Services	Control Area Transmission Agreement — PG&E Rate Schedule FERC No. 224	Transmission and various other services	Terminated 12/31/01. PG&E filing of FERC termination pending submittal of a filing to FERC.	
6.	DOE Laboratories, WAPA	PG&E/WAPA/DOE-SF 10/30/98 Settlement Agreement — PG&E Rate Schedule FERC No. 147	Transmission Service	3/31/2009	
7.	Lawrence Livermore National Laboratory, WAPA	PG&E/WAPA/DOE -SF Settlement Agreement — PG&E Rate Schedule FERC No. 147	Standby Transmission Service	3/31/2009	
8.	Midway-Sunset Co- Generation	Cogeneration Project Special Facilities — PG&E Rate Schedule FERC No. 182	Interconnection, transmission	1/1/2017	
9.	Minnesota Methane	Service Agreement No. 1, under FERC Electric Tariff, First Revised Volume No. 12	Firm Point-to-Point Transmission Service — OAT	10/1/2016	Effective 10/1/96
10.	Modesto Irrigation District	Interconnection Agreement — PG&E Rate Schedule FERC No.116	Interconnection, transmission, power sales	4/1/2008	Power sales are coordination sales — voluntary spot sales
11.	NCPA, CSC, CDWR	Castle Rock-Lakeville CoTenancy Agreement — PG&E Rate Schedule FERC No. 139	Transmission facilities maintenance	Evergreen, or 1 year notice after 1/1/2015	

12.	Path 15 Operating Instructions Settlement — Various, see FERC Docket No. ER99-1770-001	Exhibit B-1 to this Appendix B to the TCA	Implements curtailment priorities consistent with various Existing Transmission Contracts. Establishes Path 15 Facilitator role for PG&E.	3/31/2003	
13.	Power Exchange	Control Area Transmission Service Agreement — PG&E Rate Schedule FERC No. 186	Transmission and various other services	3/1/2000, or may extend if Destec does	
14.	Puget Sound Power & Light	Capacity and Energy Exchange — PG&E Rate Schedule FERC No. 140	Power exchanges	Terminates in 2007 per 5 year advance written notice received from Puget in 2002.	
15.	San Francisco (City and County of)	Interconnection Agreement — PG&E Rate Schedule FERC No. 114	Interconnection, transmission and supplemental power sales	7/1/2015	Power sales are Firm Partial Requirements
16.	Santa Clara (City of)	Mokelumne Settlement and Grizzly Development Agreement — PG&E Service Agreement No. 20 under FERC Electric Tariff Sixth Revised Volume No. 5	Transmission, power sale	1/1/2034	
17.	SCE, SDG&E	Calif. Companies Pacific Intertie Agreement — PG&E Rate Schedule FERC No. 38	Transmission service	7/31/2007	Both entitlement and encumbrance.
18.	SCE, Montana Power, Nevada Power, Sierra Pacific	WSCC Unscheduled Flow Mitigation Plan — PG&E Rate Schedule FERC No. 221	Operation of control facilities to mitigate loop flows	Evergreen, or on notice	No transmission services provided, but classify as an entitlement since loop flow is reduced or an encumbrance if we are asked to cut.

19.	Shelter Cove	Interconnection Agreement- PG&E Rate Schedule FERC No. 198	Distribution	6/30/2006	Effective 8/15/96
20.	Sierra Pacific	Interconnection Agreement — PG&E Rate Schedule FERC No. 72	Interconnection and support services	Evergreen, or 3 years notice	
21.	SMUD	Interconnection Agreement — PG&E Rate Schedule FERC No. 136	Interconnection and transmission services	12/31/2009	
22.	SMUD	EHV Transmission Agreement — PG&E Rate Schedule FERC No. 37	Transmission	1/1/2005	
23.	SMUD	Camp Far West Transmission Agreement — PG&E Rate Schedule FERC No. 91	Transmission	No notice of termination filed with FERC	
24.	SMUD	Slab Creek Transmission Agreement — PG&E Rate Schedule FERC No. 88	Transmission	No notice of termination filed with FERC	
25.	(TANC) and other COTP Participants	Coordinated Operations Agreement — PG&E Rate Schedule FERC No. 146	Transmission system coordination, curtailment sharing, rights allocation, scheduling.	1/1/2043, or earlier if other agreements terminate	Establishes relationship of the COTP to the Control Area Operator.
26.	(TANC) and other COTP Participants	COTP Interconnection Rate Schedule — PG&E Rate Schedule FERC No. 144	Interconnection	Upon termination of COTP	

27.	TANC	Midway Transmission Service / South of Tesla Principles — PG&E Rate Schedule FERC No. 143	Transmission, curtailment priority mitigation, * replacement power	Same as the COTP Interim Participation Agreement, subject to exception	
28.	Turlock Irrigation District	Interconnection Agreement — PG&E Rate Schedule FERC No. 213	Interconnection, transmission, power sales	4/1/2008, subject to exception	Power Sales are Firm Obligation Sales (Partial Requirements); Contract Firm (Firm Sale requested by TID); and Coordination Sales — Voluntary Spot Sales
29.	Vernon (City of)	Transmission Service Exchange Agreement — PG&E Rate Schedule FERC No. 148	Transmission service	7/31/2007, or by extension to 12/15/2042	Both entitlement and encumbrance. PG&E swap of DC Line rights for Vernon's COTP rights
30.	WAPA	San Luis Unit — Contract No. 2207A — PG&E Rate Schedule FERC No. 79	Transmission	4/1/2016	
31.	WAPA, SCE & SDG&E	EHV Transmission Agreement — Contract No. 2947A — PG&E Rate Schedule FERC No. 35	Transmission rights, exchange and coordination, and transmission service	1/1/2005, unless extended by agreement of the parties.	Both entitlement and encumbrance.
32.	WAPA	Sale, Interchange and Transmission — Contract No. 2948A — PG&E Rate Schedule FERC No. 79	Integration, interconnection, transmission and power sales and exchanges	1/1/2005	

* Includes use of PG&E's DC Intertie or PDCI for prespecified mitigation of curtailments over Path 15.

33.	WAPA	Wintu Pumping Plant — Contract No. 2979A — PG&E Rate Schedule FERC No. 79	Transmission	Concurrent with Contract No. 2948A expiration of 1/1/2005	
34.	WAPA	Delta Pumping Plant — Contract No. DE-AC65-80WP59000 — PG&E Rate Schedule FERC No. 63	Transmission	Concurrent with Contract No. 2948A expiration of 1/1/2005, or 3 years notice	
35.	WAPA	Healdsburg, Lompoc & Ukiah — Contract No. DE-MS65-83WP59055 — PG&E Rate Schedule FERC No. 81	Transmission	Concurrent with Contract No. 2948A expiration of 1/1/2005, or 4 years notice	
36.	WAPA	Sonoma County Water Agency — Contract No. 88-SAO-40002 — PG&E Rate Schedule FERC No. 126	Transmission	6/30/94, or concurrent with Contract 2948A expiration of 1/1/2005, or 4 years notice	
37.	WAPA	New Melones — Contract No. 8-07-20-P0004 — PG&E Rate Schedule FERC No. 60	Transmission	6/1/2032	Per WAPA, commercial operation date for New Melones was 6/1/82
38.	WAPA	Trinity County PUD & Lewiston Power Plant — Contract No. 93-SAO-18008, Supplement No. 42 — PG&E Rate Schedule FERC No. 79	Transmission	1/1/2005	

Lien Mortgage

The lien of the First and Refunding Mortgage dated December 1, 1920 between PG&E and BNY Western Trust Company, as trustee, as amended and supplemented and in effect on the date hereof (the "PG&E Mortgage"). The transfer of Operational Control to the ISO pursuant to this Agreement shall in no event be deemed to be a lien or charge on the PG&E Property which would be prior to the lien of the PG&E Mortgage; however, no consent of the trustee under the PG&E Mortgage is required to consummate the transfer of Operational Control to the ISO pursuant to this Agreement.

EXHIBIT B-1
(TO PG&E APPENDIX B)
Path 15 Operating Instructions
For Existing Encumbrances Across the Path 15 Interface
April 1, 2003, Revision 1

Introduction

As contemplated by the ISO Tariff, and as directed by the Federal Energy Regulatory Commission in its orders on Amendments 3 and 7 to the ISO Tariff, which were filed by the ISO, Pacific Gas and Electric Company (PG&E) has worked with the parties with whom it has existing contracts for transmission service over Path 15 (ETC Parties), in order to develop these Operating Instructions, which, pursuant to sections 2.4.3.1, 2.4.4.4.1, and 2.4.4.4.3 of the ISO Tariff, are to be followed by the ISO in operating this constrained Path. The constraints on Path 15 have been known by all transmission users for many years and have not been alleviated by the creation or operation of the ISO. The Operating Instructions which follow are intended to preserve each ETC Party's pre-existing contract rights¹ to transmission service over Path 15 and PG&E's use of that transmission path. These Operating Instructions will remain in place until PG&E submits replacement instructions to the ISO. PG&E will not submit revised operating instructions to become effective prior to January 1, 2005, except as necessary due to a materially revised ISO market design or to reflect a material change in ETC rights. All parties reserve all rights to argue for the implementation of different Operating Instructions and priorities for Path 15 consistent with their ETC contract rights, in the event PG&E submits any revised Operating Instructions. Further, any party may oppose any modification of these Operating Instructions that materially affects the rights of such party as set forth herein. Any Party that believes these Operating Instructions should be revised may at any time present the suggested revision to PG&E for its consideration.

1/ These operating instructions apply only to unexpired contract rights. Expired contracts will be removed from these instructions at the time of any revision or update. The inclusion of an expired contract in these instructions pending a revision in which the expired contract rights are removed does not confer any extension of such contract.

Purpose and Objectives

These Path 15 Operating Instructions provide direction to the ISO regarding the management of congestion on Path 15 during the ISO's Day Ahead, Hour Ahead and Real Time markets. The objective of these instructions is to assure, on an ongoing basis, the efficient use each day of available Path 15 transfer capability while maintaining the transmission rights and priorities on Path 15 that were in existence as of the ISO Operations Date. These instructions also clarify individual and joint responsibilities between the ISO as the Control Area Operator and PG&E as the Path 15 Existing Transmission Contract (ETC) Facilitator.¹

These instructions are to be adhered to *except* when the ISO determines that system reliability requires that other steps be taken. The ISO is solely responsible for continued system reliability and must unilaterally take all steps necessary to preserve the system in times of emergency.

- 1/ Specific operating instructions have been provided to the ISO by PG&E in other documents for each of the Existing Contracts for which it is the Responsible Participating Transmission Owner on Path 15. In the contract specific instructions, information is provided on the maximum MW of transmission service available over the path; the quality of transmission service; daily, hourly and real time scheduling rights and responsibilities; curtailment procedures; points of receipt and points of delivery and effective and termination dates of the contract. This set of additional instructions will clarify how the relative transmission rights and priorities of the parties should be managed and administered during times of congestion and possible curtailment on Path 15.

Path 15 Existing Transmission Contract Facilitator (ETC Facilitator)

PG&E will serve in the capacity of ETC Facilitator to assist the ISO and to provide necessary guidance to the ISO in the administration of Path 15 ETC rights. The ETC Facilitator shall:

1. Provide to the ISO, for each hour of the Trading Day, the total amount of megawatts that should be reserved for use by the ETC Parties.
^{2/} Such amounts shall be provided generally by 8:30 a.m. of each weekday prior to the start of a Trading Day for the Day-Ahead Market, and generally by 4:30 p.m. of the weekday prior to the start of a Trading Day for the Hour-Ahead Market.³ Any revisions to the amount of megawatts reserved for use by the ETC Parties after these times shall be as provided in ISO operating procedures (currently M-423).
 - 2/ The ETC Facilitator's specification of the megawatt reservation amount does not limit, in any way, ETC Parties' ability to exercise their rights, including making schedule changes in real time.
 - 3/ PG&E and most of the ETC Parties pre-schedule Monday through Friday only. PG&E generally provides its ETC reservation for Sunday and Monday by close-of-business on Friday and to the extent practicable, encourages ETC Parties to provide pre-schedules in time to meet the ISO's Day-Ahead market deadline.
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2. Facilitate all Path 15 schedules from ETC Parties, including those ETC Parties for which the ETC Facilitator is not the Scheduling Coordinator (SC), unless otherwise agreed by PG&E and the ETC Party. ¹
 3. Schedule all SC to SC transfers ² that utilize ETC rights across Path 15, unless otherwise agreed by PG&E and the ETC Party.
 4. Inform ETC Parties, affected SCs, and the ISO, pursuant to these Operating Instructions, when an ETC Party's scheduled usage of Path 15 is reduced and the amount of such reduction.
 5. In performing these tasks, ensure that all transmission rights and priorities on Path 15 that were in existence as of the ISO Operations Date are maintained and protected.
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- 1/ PG&E may make arrangements with an ETC party to permit that party to self schedule its Path 15 rights. Any such arrangements will preserve the purpose and objectives of these Operating Instructions.
- 2/ Currently, Southern California Edison Company (Edison) schedules its SC-SC transfers for its Existing Contracts directly with the ISO. Upon mutual agreement by Edison and PG&E, PG&E may become a party to these SC-SC transfers across Path 15.

Day-Ahead Market Congestion Management

Prior to the start of the ISO Day-Ahead process, the ETC Facilitator will provide the ISO with an hourly reservation for ETC schedules utilizing Path 15. The ISO will determine the hourly amount of the Path 15 operating limit available for New Firm Uses ³ for use in its Congestion Management Process ⁴ by subtracting the ETC megawatt reservation amount from the operating limit for Path 15 for each hour. After the deadline for receiving Day-Ahead Preferred Schedules, the ISO performs its Congestion Management Process and determines the Usage Charges, if any, for each hour of congestion on Path 15. ETC Parties whose schedules over Path 15 are submitted to the ISO by the ETC Facilitator will not be assessed Usage Charges associated with their Path 15 schedules by the ETC Facilitator.

- 3/ Regulatory Must Take and Regulatory Must Run resources that contribute to the "imputed use" of Path 15 are treated as New Firm Uses for this purpose. The "imputed use" is the expected power flow resulting from the load, interchange, and resource schedules of all SCs.
- 4/ The ISO's Congestion Management Process uses Adjustment Bids to reduce the amount of New Firm Use, if necessary, so that such use does not exceed the amount of the Path 15 operating limit less the ETC reservation megawatt amount.

Hour-Ahead Market Congestion Management

Because scheduling timelines in ETC Parties' contracts (including third party contracts using ETC Party rights) differ from the ISO's scheduling timeline, some pre-schedules from such parties are likely to be scheduled in the Hour-Ahead Market. The ETC Facilitator's ETC megawatt reservation amount submitted in the Day-Ahead Market is intended to provide sufficient reservation to accommodate the schedules submitted in the Hour-Ahead Market. After the close of the Hour-Ahead Preferred Market, the ISO performs its Congestion Management Process and determines the Usage Charges, if any, for such hour on Path 15. ETC Parties whose schedules over Path 15 are submitted to the ISO by the ETC Facilitator will not be assessed Usage Charges associated with their Path 15 schedules by the ETC Facilitator.

Real Time Curtailment Priorities

Any and all ETC Parties' rights (including third party contracts using ETC Party rights) to change schedules after the close of the ISO's Hour-Ahead market will continue to be honored. In the event of curtailments on Path 15 South-to-North in real time, the ETC Facilitator will determine the appropriate order and magnitude of curtailments given the circumstances that occur in real time and the terms and provisions of the ETCs. This determination will be made consistent with the following table "Path 15 South-to-North Real-Time Curtailment Priorities", a copy of which is Attachment A, which is incorporated into and made a part of these Path 15 Operating Instructions by this reference.

In Attachment A, the relative priorities of the various ETC Parties' transmission service rights across Path 15 in real-time are identified by grouping the various rights into separate blocks and ordering the blocks by their relative priority. Attachment A addresses only Path 15 *South to North* real-time curtailment priorities. The Path 15 *North-to-South* real-time curtailment priorities will be addressed in a separate and distinct set of Operating Instructions and will be separately submitted to the ISO after review by the Path 15 ETC Parties.

**EXHIBIT B-1
(TO PG&E APPENDIX B)**

Path 15 Real-Time South-to-North Curtailment Priorities ^{1/}

Priority Group	ETC/Priority Holder	South-to-North
1 ²	CDWR EHV Agreement ³	300 MW
	SCE CCPIA encumbered rights	320 MW
	SDG&E CCPIA encumbered rights	0
	PG&E must-take encumbrances	4
	CDWR Comprehensive Agreement	810 MW
2	TANC SOTP ⁵	300 MW
3	TID IA (Reserve rights)	32 MW
4 ⁶	PG&E SOTP	500 MW
	SCE CCPIA unencumbered rights ^{7/}	347 MW
	SDG&E CCPIA unencumbered rights ^{7/}	109 MW
5	New ETC Requests ^{7/}	unspecified
	Other "As Available"	

- 1/ This table may change from time to time as existing contracts are terminated, or the rights under those contracts change (e.g., termination of a QF contract).
- 2/ Curtailments within Priority Group 1 are based on each party's contract right or entitlement amount.
- 3/ CDWR has both EHV and Comprehensive Agreement rights. When curtailments are required, CDWR's EHV schedules are curtailed beginning at the then-current maximum operating limit of the path (as it may increase or decrease from time to time).
- 4/ The Priority Group 1 capacity available to PG&E south-to-north in real time is the capacity remaining after CDWR's EHV and SCE/SDG&E's CCPIA Existing Contract schedules (as may be curtailed) are subtracted from the amount of available capacity. This remaining capacity is available for CDWR's Comprehensive Agreement schedules and PG&E's must-take encumbrances. PG&E's must-take encumbrances rights correspond to the amount of Path 15 south-to-north transfer capability historically available for PG&E must-take generation in ZP26, including but not limited to the generation of PG&E's Diablo Canyon Nuclear Power Plant, minus PG&E load in ZP26. As used in this footnote, "PG&E's must-take encumbrances" means an amount of transmission transfer capability that is reserved for ISO New Firm Uses across Path 15 south-to-north that is the lesser of PG&E's must-take encumbrances rights defined above or the IOU imputed use of Path 15. The IOU imputed use of Path 15 is the expected power flow resulting from the load, interchange and resource schedules of PG&E, SCE and SDG&E across Path 15. CDWR's Comprehensive Agreement schedules are curtailed, pro rata with the Priority Group 1 capacity available to PG&E, beginning at the then-current maximum operating limit of the path (as it may increase or decrease from time to time).
- 5/ TANC's 300 MW is firm bi-directional service using the Points of Receipt and Delivery set forth in section 2.4 of the SOTP and in accordance with the Curtailment Priorities set forth in section 3.2 of the SOTP. PG&E supports these transfer capabilities by implementing mitigation measures when necessary, to the extent such measures are available, up to a total of 200 MW south-to-north and 700 MW north-to-south. These mitigation measures consist of switching PG&E's scheduled transmission service from the AC Lines to the DC Line.
- 6/ Priority Group 4 is available for ISO use for New Firm Uses.
- 7/ "New ETC Requests" includes any requested service by an ETC in excess of the rights set forth in this table for Priority Groups 1-4, provided that this footnote shall not apply to arrangements between or among PG&E and one or more ETC Parties for future capacity upgrades, if such parties agree, or an existing contractual commitment provides otherwise.

ATTACHMENT 1

CALIFORNIA ISO PATH 15 ATC DETERMINATION METHODOLOGY

Note: This document is intended to explain the procedures for calculation and allocation of Available Transfer Capacity (ATC) over Path 15 pursuant to the Federal Energy Regulatory Commission's May 22, 2002 order in Docket ER99-1770-001 (99 FERC ¶ 61,212). It should not be interpreted in any way to modify Exhibit B-1 of the Transmission Control Agreement.

California ISO calculation of Path 15 ATC in the Day Ahead and Hour Ahead Markets (largely described in Exhibit B-1):

1. The ISO calculates the Operating Transfer Capability (OTC) for Path 15 and calculates the Existing Contract (ETC) rights of the Edison ETC rights holders.
2. By 8:30 a.m. of each week day prior to the start of the Trading Day PG&E submits to the ISO the ETC capacity to be reserved in the Day Ahead Market, and by 4:30 p.m. of each week day prior to the start of the Trading Day PG&E may submit a revised ETC reservation amount to the ISO for the ETC capacity to be reserved in the Hour Ahead Market. Any revisions to the amount of megawatts reserved for use by the ETC Parties after these times shall be as provided in ISO operating procedures (currently M-423). (The amount reserved by PG&E in the Day-Ahead Market is based on pre-scheduled amounts submitted by the PG&E-facilitated ETC rights holders to PG&E by 8:15 a.m. or on the previous day's schedules and PG&E's view of the capacity that will be used by such ETC rights holders, with an additional amount of margin to ensure that sufficient capacity is available to the PG&E-facilitated ETC rights holders that wish to modify their pre-scheduled use of their capacity in the Hour-Ahead and real time scheduling processes. PG&E can but does not ordinarily provide updates in advance of the Hour Ahead Market.)
3. The ISO subtracts the capacity reserved for the PG&E-facilitated and Edison ETC rights holders over Path 15 from the Path 15 OTC to determine the ATC available for New Firm Uses (NFU).

Allocation of ATC on Path 15 in real-time, i.e. calculate ETC available rights and curtailments based on applicable priorities (largely described in Exhibit B-1 and Attachment A to Exhibit B-1):

1. *Path 15 OTC* : Confirm Path 15 South-to-North OTC and adjust for Unscheduled Flows.
 2. *Priority Group 1 ETCs* : Retrieve all actual schedules by ETC Parties in Priority Group 1 (as set forth in Attachment A to Exhibit B-1) from all SCs scheduling on behalf of such parties over Path 15.
 3. *PG&E Must Take Encumbrance and IOU Imputed Use* : Retrieve amounts for PG&E Must-Take Encumbrance (which is available for NFU, but needed to assess certain parties' ETC rights) and the IOU Imputed Use—formerly PX Imputed Use—as set forth in footnote 4 of Attachment A to Exhibit B-1). Adjust, if necessary, for known changes in generation amounts from amounts forecast in Day Ahead Markets.
 4. *Capability Available to Lower Priority ETCs* : Subtract from the Path 15 OTC the amounts for Priority Group1 ETCs actual net south-to-north scheduled amounts (2 above) and for each hour the lesser of PG&E's Must Take Encumbrance or the IOU Imputed Use (3 above). This is the amount of transmission capacity available for lower priority ETCs (as set forth in Attachment A to Exhibit B-1).
 5. *ATC Available for NFU* : All ATC not used by ETC Parties is available for NFU (this includes any amount remaining after subtracting from the Path 15 OTC the Priority Group 1-3 ETCs actual scheduled amounts as they are adjusted for any real-time curtailments). Thus the lesser of the PG&E Must Take Encumbrance or the IOU Imputed Use has priority over Priority 2-3 ETCs, but shares the available OTC with Priority 1 ETCs actually scheduled amounts.
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Thus, in real time, NFU access to transmission capacity over Path 15 has two levels of priority:

- First, as the capacity represented by the lesser of the PG&E Must Take Encumbrance or the IOU Imputed Use amount, which has priority over lower priority ETCs and may use the unscheduled rights of Priority 1 ETC rights holders, and
- Second, as any capacity that remains after subtracting from OTC the actual schedules for Priority 1-3 ETCs and the NFU amount above.

However, operationally the ISO does not allocate particular NFU schedules to a particular priority but rather treats all NFU schedules as a single block. The following example illustrates how this occurs:

Assume that OTC over Path 15 is 2,500 MW in a given hour and that there is no Unscheduled Flow. Assume that there are 800 MW of Priority 1 ETC actual schedules, 1,000 MW of PG&E Must Take Encumbrance, 200 MW of lower priority ETC actual schedules, and 1,500 MW of NFU. This NFU amount, as described above, uses the 1,000 MW of PG&E Must Take Encumbrance and the amount of capability remaining after accommodating the lower priority ETC schedules. Assume that Path 15 is derated to 2,000 MW. In this example, no ETC curtailment is indicated, thus the ISO must take actions to reduce the flow. The ISO would use Adjustment Bids and Supplemental Energy bids in the BEEP stack to attempt to accommodate the transactions without curtailing any of the NFU schedules. Assume that after bids in the BEEP stack are exhausted, 1,200 MW of NFU remain on Path 15 and curtailments are required (this occurrence is rare). If feasible within the time available to manage the Path derating, the 1,200 MW of NFU would be curtailed on a pro-rata basis to result in NFU of 1,000 MW. Assume that Path 15 is further derated to 1,000 MW and that all bids in the BEEP stack remain exhausted. If feasible within the time available to manage the Path derating, the 1,000 MW of NFU (the amount that is using the priority rights equal to the amount of the PG&E Must Take Encumbrance) would be curtailed on a pro-rata basis to result in NFU of 200 MW and the lower priority ETC schedules would be curtailed to 0 MW. Note: Priority 1 ETC rights are determined on the basis of the Path 15 OTC, and only curtailed if the Priority 1 ETC rights holder's schedule exceeds its contract right or entitlement amount.

TRANSMISSION CONTROL AGREEMENT

APPENDIX C

ISO MAINTENANCE STANDARDS

1. DEFINITIONS(1)

Availability— A measure of time a Transmission Facility under ISO Operational Control is capable of providing service, whether or not it actually is in service.

Availability Measures— The frequency and accumulated duration of Forced Outages ^(IMS) for each of the Transmission Line Circuits within a Voltage Class for a given calendar year.

Availability Measure Targets— The Availability performance goals established by the ISO.

Forced Outage ^(IMS)—A Forced Outage ^(IMS) occurs when a Transmission Facility is in an Outage ^(IMS) condition regardless of duration and: (1) there is no Scheduled Outage request in effect with respect to that period; or (2) the Transmission Facility is in an Outage ^(IMS) condition for a period that exceeds the period specified in the Scheduled Outage request, in which case a Forced Outage ^(IMS) is deemed to exist for the balance of the period, unless the PTO requests and is granted an extension to the approved Scheduled Outage request.

ISO Maintenance Guidelines— Criteria presented herein which are to be followed by each PTO in preparing its PTO Maintenance Practices.

ISO Maintenance Standards— Those maintenance standards which result from the combination of each PTO's Maintenance Practices and their respective Availability Measures.

Maintenance— Maintenance as used herein, unless otherwise noted, encompasses inspection, assessment, maintenance, repair and replacement activities.

Maintenance Coordination Committee— A committee responsible for recommending to the ISO modifications to and implementation of the ISO Maintenance Standards. The committee shall be organized and operate in accordance with Section 7.0 of this document.

Outage ^(IMS)— Any interruption of the flow of power in a Transmission Line Circuit between any terminals under ISO Operational Control.

PTO— A Participating Transmission Owner as defined in Appendix D of the Transmission Control Agreement.

PTO Maintenance Practices— A description of methods used by a PTO for the Maintenance of each substantial type of Transmission Facility or component in its system which is under the Operational Control of the ISO. The PTO Maintenance Practices are to be prepared in accordance with the ISO Maintenance Guidelines.

Scheduled Outage— The removal from service of a Transmission Facility under ISO Operational Control to perform work on specific components in accordance with the requirements of the Transmission Control Agreement.

Section 348 Criteria— The criteria for maintenance standards established by Section 348 of the California Public Utilities Code, as in effect from time to time, to "provide for high quality, safe and reliable service", taking into consideration "cost, local geography and weather, applicable codes, national electric industry practices, sound engineering judgment, and experience".

(1) A term followed by the superscript "(IMS)" denotes a term which has a special, unique definition in this Appendix.

Stations— Facilities under the Operational Control of the ISO for purposes such as line termination, voltage transformation, voltage conversion, stabilization, or switching.

Transmission Facilities —All equipment and components transferred to the ISO for Operational Control, pursuant to the Transmission Control Agreement, such as overhead and underground transmission lines, Stations, and system protection equipment.

Transmission Line Circuit— The continuous set of transmission conductors located primarily outside of a Station, and apparatus terminating at interrupting devices which would be isolated from the transmission system following a fault on such equipment.

Voltage Class— The voltage to which operating, performance, and maintenance characteristics are referenced. Voltage Classes are defined as follows:

Voltage Class	Range of Nominal Voltage
69 kV	≤ 70 kV
115 kV	110 - 161 kV
230 kV	200 - 230 kV
345 kV	280 - 345 kV
500 kV	500 kV
HVDC	HVDC

2. INTRODUCTION

These standards were prepared by the ISO through a lengthy consensus building effort involving a diverse group of stakeholders (i.e., the ISO Maintenance Standards task force).

2.1. Objective

The Maintenance of Transmission Facilities has several objectives:

- Ensuring that the safety and Availability performance levels inherent to the Transmission Facilities are achieved,
- Restoring the safety and Availability to the levels inherent to the Transmission Facilities when degradation has occurred,
- Gathering information that can be of use as the basis for identifying improvements to those Transmission Facilities whose Availability performance is inadequate,
- Gathering information that can be used as the basis for optimizing and forecasting Maintenance for Transmission Facilities,
- Extending the useful life of the Transmission Facilities while maintaining their inherent levels of Availability, and
- Achieving the aforementioned objectives at a minimum total cost for Maintenance and Outages.

The ISO Maintenance Standards address the following topics:

- Transmission Facilities Covered by the ISO Maintenance Standards;
- Availability Measures ;
- Availability Measure Targets;
- ISO Maintenance Guidelines for PTO Maintenance practices;
- Qualifications of Maintenance Personnel;

- Maintenance Record Keeping and Reporting;
- Establishment of a Maintenance Coordination Committee;
- Process for the Revision of the ISO Maintenance Standards;
- Incentives and Penalties for PTO Availability Performance;
- Compliance with Laws and Regulations; and
- Dispute Resolution.

For certain aspects of Maintenance, these Standards delineate specific requirements and responsibilities (e.g., requirements for PTO inspection and Maintenance records), for others they provide guidelines (e.g., contents of PTO Maintenance Practices documents), and for others they describe processes (e.g., review process for PTO Maintenance Practices documents) to be enacted to achieve the desired results.

Flexibility in establishing ISO Maintenance Standards is implicit in the goal of optimizing Maintenance across a system characterized by diverse environmental and climatic conditions, terrain, equipment, and design practices. To provide for flexibility while ensuring the reasonableness of each PTO's approach to Maintenance, the ISO Maintenance Standards are founded on two basic precepts: 1) the effectiveness of each PTO's Maintenance will be gauged through an Availability performance monitoring system, and 2) the adequacy of each PTO's Maintenance Practices will be assessed through ISO review. Each PTO's Maintenance Practices will serve as the ISO's Maintenance Standards for the Transmission Facilities covered therein. The PTO Maintenance Practices ensure a reasonable level of Maintenance during the short term while Availability is used to monitor long term performance.

It is the belief of the ISO Maintenance Standards task force that it is impractical for the ISO to develop and/or impose on the PTO's a single uniform set of detailed descriptions of practices delineating condition or time-based schedules for various Maintenance activities that account for the myriad equipment, operating conditions, and environmental conditions within the ISO grid. For this reason, the ISO Maintenance Standards provide ISO Maintenance Guidelines to be followed by each PTO in preparing PTO Maintenance Practices for its Transmission Facilities.

2.2. Availability

ISO grid reliability is a function of the Availability of Transmission Facilities owned and operated by its PTO's. The key to the effectiveness of the ISO Maintenance Standards is the establishment of a consistent measure of Transmission Facility Availability (Availability Measures) and the initial setting of the Availability Measure Targets as well as periodic revisions of those targets. By measuring Availability the ISO is able to monitor the effectiveness of Maintenance. While the ISO is concerned with grid reliability, reliability is a function of a complex set of variables including the accessibility of alternative load paths, speed and sophistication of protective equipment, and the Availability of Transmission Line Circuits, and therefore is indirectly related to Maintenance. Thus, Availability will be the principal determinant of each PTO's performance under the ISO Maintenance Standards.

When using Availability as a gauge of Maintenance adequacy, several things must be kept in mind to avoid misinterpreting performance. The most important consideration is that across the ISO grid, the vast majority of all Forced Outages ^(IMS) are due to random/chance events that cannot be controlled by Maintenance. It is important to recognize that only a small percentage of all Forced Outages ^(IMS) can be controlled through Maintenance (i.e. activities that do not change the basic configuration of Transmission Facilities). This principle assumes the PTO is performing a reasonable level of Maintenance consistent with Good Utility Practice. If an unreasonably low level of Maintenance is performed for a sufficient period of time, Availability will decline. However, if a level of Maintenance is being performed, consistent with Good Utility Practice, increasing Maintenance activities by a

significant order will not result in a corresponding increase in Availability. Thus, while Maintenance is important to ensuring Availability, drastic increases in Maintenance will not lead to substantial improvements in Transmission Facility Availability and associated grid reliability.

A variety of techniques can be used to monitor performance, however techniques that do not account for random variations in processes have severe limitations in that they may yield inconsistent and/or erroneous assessments of performance. To account for random/chance variations while enabling monitoring for shifts and trends in performance, control charts have been widely accepted as an effective means for monitoring performance. Control charts are statistically-based graphs which illustrate both an expected range of performance for a particular process based on historical data, and discrete measures of recent performance. The relative positions of these discrete measures of recent performance and their relationship to the expected range of performance are used to gauge the adequacy of performance. Availability is affected by several factors only one of which is Maintenance. In fact, for most Transmission Line Circuits only a small fraction of Forced Outages^(IMS) can be attributed to phenomenon that could be controlled or avoided through Maintenance. Many more Forced Outages^(IMS) are attributable to random/chance events than Maintenance-related items. Therefore, while monitoring Availability as a gauge of Maintenance adequacy is useful for evaluating long term trends, care must be taken to avoid reading too much into the correlation of Availability to Maintenance since so many additional variables also impact Availability.

The fundamental performance measures selected as the basis for developing an Availability performance monitoring system are the annual accumulated duration and frequency of certain types of Outages for each Transmission Line Circuit under the ISO's Operational Control. To enhance the Availability performance monitoring system's use as a gauge of Maintenance adequacy, it was necessary to exclude certain Outage^(IMS) types from the determination of the performance measures. Those excluded Outages are:

- Scheduled Outages;
- Outages caused by events originating outside the PTO's system; and
- Outages demonstrated to have been caused by earthquakes.

Additionally, the Forced Outage^(IMS) duration has been capped at 72 hours so that excessively long Forced Outages^(IMS) do not skew the data as to detract from the meaningfulness and interpretation of the control charts for accumulated Forced Outage^(IMS) duration. This is not to say that an excessively long Forced Outage^(IMS) is not a concern. Rather, such Forced Outages^(IMS) should be investigated to assess the reasons for their extended duration.

The performance monitoring system requires use of separate control charts for each Voltage Class and PTO. Existing Forced Outage^(IMS) data contains significant differences in the Availability performance between Voltage Classes and between PTOs. These differences may be attributable to factors such as the uniqueness of operating environments, Transmission Facility designs, and PTO operating policies. However, regardless of the cause of the differences, review of the Forced Outage^(IMS) data makes it eminently apparent that the performance differences are such that no single set of control chart parameters for a particular Voltage Class could be applied to all PTOs.

Three types of control charts will be constructed to provide a complete representation of historical Availability performance, and to provide a benchmark against which future performance can be gauged. The three types of control charts for each PTO and Voltage Class are:

- The annual average Forced Outage^(IMS) frequency for all Transmission Line Circuits;
- The annual average accumulated Forced Outage^(IMS) duration for those Transmission Line Circuits which experience Forced Outages^(IMS); and

- The annual proportion of Transmission Line Circuits that experienced no Forced Outages ^(IMS).

These three control charts will assist the ISO and PTO's in assessing the performance of Voltage Classes over time. To accommodate this process on a cumulative basis data are made available to the ISO by each PTO at the beginning of a new year to assess the performance of the past years.

2.3. ISO Maintenance Guidelines

Two specific requirements regarding Maintenance documentation have been incorporated into the ISO Maintenance Standards. First, these standards require that each PTO develop and submit a description of its Maintenance practices (PTO Maintenance Practices) to the ISO. Second, these standards require that each PTO maintain Maintenance records and make those records available to the ISO in order to demonstrate compliance with each element of its PTO Maintenance Practices.

To outline the fundamental requirements for, and to promote consistency in the PTO Maintenance Practices, these standards provide guidelines for the preparation and maintenance of the PTO Maintenance Practices. These ISO Maintenance Guidelines provide for flexibility in approach to Maintenance, but also require the description of certain specific Maintenance practices. The guidelines require that the PTO's provide descriptions of the various Maintenance activities, schedules and condition triggers for performing the Maintenance, and samples of any checklists, forms, or reports used for Maintenance activities.

2.4. Data Standards

To facilitate processing of Outage ^(IMS) data for the Availability performance monitoring system, and to enable consistent and equitable interpretation of PTO Maintenance records by the ISO, these standards address the need for data recording and reporting. The ISO and PTO's have committed to developing standardized formats for transmitting Outage ^(IMS) data to the ISO for the Availability performance monitoring system. These standard formats are to be finalized within the first 60 days of 1998. Additionally, the ISO and PTO's have agreed to develop and implement a standard Maintenance reporting system by the end of the third year of operation of the ISO. This system will provide for consistent gathering of information that can be used as the basis for optimizing and forecasting maintenance of Transmission Facilities. The development of such a Maintenance reporting system is consistent with fostering the spirit of cooperation among the ISO and the PTO's as it may eventually aid in the resolution of performance problems, and provide the basis for research on an ISO grid-wide basis to identify opportunities to enhance Transmission Facility Maintenance.

2.5. Applicability of Incentives and Penalties

Cooperation and collaboration among the PTOs responsible for ensuring the Availability of the Transmission Facilities comprising the ISO grid are needed to ensure the most reliable grid possible. Therefore, the ISO Maintenance Standards task force believes that a formal program of incentives and penalties tied purely to PTO Maintenance may hinder needed cooperation among PTOs. As a result, the ISO Maintenance Standards task force recommends that no such program be instituted initially by the ISO.

Further, the task force recognizes the need for the ISO to enforce reasonable Maintenance to ensure Availability in the case that: 1) a PTO exhibits degradation in Availability performance due to Maintenance, 2) a PTO does not comply with its PTO Maintenance Practices, or 3) a PTO is grossly or willfully negligent with regards to Maintenance. Therefore, it is the position of the ISO Maintenance Standards task force that it is reasonable for the ISO to establish penalties for such conditions. In the absence of a formal program of incentives and penalties, the task force acknowledges the ISO's right to pursue sanctions for cause on a case by case basis.

Availability is a useful and tractable means for monitoring performance, however, the electric utility industry as a whole has little experience in using Availability to gauge the adequacy of Maintenance. Further, because the industry in general has not carefully managed historical Outage ^(IMS) data to the degree that is necessary to make them useful for performance monitoring, there are varying limitations with regards to the accessibility and reliability of Outage ^(IMS) data among PTOs. Also, the impact on Availability when a new entity, namely the ISO, assumes Operational Control of the grid is unknown. Thus, it is the position of the ISO Maintenance Standards task force that the Availability performance monitoring system will be implemented and used to gauge Availability performance beginning on the ISO Operations Date. However, the system needs to be used and updated during a five year phase in period to be considered for use in a program of incentives and penalties for Availability performance.

Availability is a function of several variables including Transmission Facility Maintenance, capital improvements, and improvements in restoration practices. If a PTO is exercising a reasonable level of Maintenance, yet the Availability performance of a Voltage Class or individual Transmission Line Circuit is inadequate for the purposes of the ISO grid, then capital improvements or improvements in restoration practices may lead to greater Availability improvements than increased Maintenance. Therefore, assessing incentives and penalties on the basis of Availability as influenced by all of these variables may be a reasonable approach for influencing PTO's to improve the Availability of their Transmission Facilities where such improvements can be justified.

3. TRANSMISSION FACILITIES COVERED BY THE ISO MAINTENANCE STANDARDS

All Transmission Facilities transferred to the ISO, pursuant to the Transmission Control Agreement, shall be maintained in accordance with the ISO Maintenance Standards.

4. AVAILABILITY STANDARD

4.1. Introduction

The ISO shall monitor and measure each PTO's Availability for the Transmission Line Circuits under ISO Operational Control. The ISO shall use an Availability measurement system which consists of two primary components: 1) measures of the annual performance of each Voltage Class based on the performance of each of the Transmission Line Circuits comprising the Voltage Class, i.e. the Availability Measures; and 2) a set of threshold performance criteria for each Voltage Class, i.e. Availability Measure Targets. The Availability Measure Targets will be used to gauge the adequacy of the PTO's annual performance for each Voltage Class. Each PTO shall make an annual report to the ISO within 90 days from the end of each calendar year that describes its compliance with the Availability Measure Targets. In its report to the ISO, supporting data based on Outage ^(IMS) records shall be included, justifying the Availability Measures reported for each Voltage Class.

4.2. Availability Measures

4.2.1. Calculation of Availability Measures for Individual Transmission Line Circuits

The calculation of the Availability Measures will be performed utilizing Outage ^(IMS) data through December 31 of each year. Separate Forced Outage ^(IMS) frequency and accumulated Forced Outage ^(IMS) duration Availability Measures shall be calculated as follows for each Transmission Line Circuit under ISO Operational Control within each Voltage Class. The calculations shall be performed annually for each of the Transmission Line Circuits utilizing all appropriate Outage data for the calendar year in question.

Forced Outage ^(IMS) Frequency:

The Forced Outage ^(IMS) frequency (f_{ik}) of the i^{th} Transmission Line Circuit shall equal the total number of Forced Outages ^(IMS) that occurred on the i^{th} Transmission Line Circuit during the calendar year k . See Notes 1 and 2.

NOTES:

1. Multiple momentary Forced Outages ^(IMS) on the same Transmission Line Circuit in the span of a single minute shall be treated as a single Forced Outage ^(IMS) with a duration of one minute. When the operation of a Transmission Line Circuit is restored following a Forced Outage ^(IMS) and the Transmission Line Circuit remains operational for a period exceeding one minute, i.e. 61 seconds or more, followed by another Forced Outage ^(IMS), then these should be counted as two Forced Outages ^(IMS). Multiple Forced Outages ^(IMS) occurring as a result of a single event should be handled as multiple Forced Outages ^(IMS) only if subsequent operation of the Transmission Line Circuit between events exceeds one minute. Otherwise they shall be considered one continuous Forced Outage ^(IMS).
2. If a Transmission Line Circuit, e.g. a new Transmission Line Circuit, is only in service for a portion of a year, the Forced Outage ^(IMS) frequency and accumulated duration data shall be treated as if the Transmission Line Circuit had been in service for the entire year, i.e. the Outage ^(IMS) data for that Transmission Line Circuit shall be handled the same as those for any other Transmission Line Circuit.

Accumulated Forced Outage ^(IMS) Duration:

The accumulated Forced Outage ^(IMS) duration in minutes shall be calculated as follows for each of the Transmission Line Circuits having a Forced Outage ^(IMS) frequency (f_{ik}) greater than zero for the calendar year k :

$$d_{ik} = \sum_{j=1}^{f_{ik}} o_{ijk}$$

where

d_{ik} = accumulated duration of Forced Outages ^(IMS) (total number of Forced Outage ^(IMS) minutes) for the i^{th} Transmission Line Circuit having a Forced Outage ^(IMS) frequency (f_{ik}) greater than zero for the calendar year k .

f_{ik} = Forced Outage ^(IMS) frequency as defined above for calendar year k .

o_{ijk} = duration in minutes of the j^{th} Forced Outage ^(IMS) which occurred during the k^{th} calendar year for the i^{th} Transmission Line Circuit. See Notes 1 and 2.

The durations of extended Forced Outages ^(IMS) shall be capped as described in Section 4.2.2. "Capping of Forced Outage ^(IMS) Duration" for the purposes of calculating the Availability Measures. In addition, certain types of events/Outages shall be excluded from the calculations of the Availability Measures as described in Section 4.2.3 "Excluded Events".

If a PTO makes changes to its Transmission Line Circuit identification, configuration, or Outage ^(IMS) data reporting schemes, the PTO shall notify the ISO at the time of the change. In its annual report to the ISO the PTO shall provide recommendations regarding how the Availability Measures and Availability Measure Targets should be modified to ensure they remain consistent with the modified Transmission Line Circuit identification or Outage ^(IMS) data reporting scheme, and that they provide an appropriate gauge of performance.

4.2.2. Capping of Forced Outage^(IMS) Durations

The durations of individual Forced Outages^(IMS) which exceed 72 hours (4320 minutes) shall each be capped at 4320 minutes for the purpose of calculating the accumulated Forced Outage^(IMS) duration.

4.2.3. Excluded Events

The following types of events/Outages shall be excluded from the calculation of the Availability Measures and the Availability Measure Targets:

- *Scheduled Outages* which are scheduled, reviewed and approved by the ISO in accordance with the Transmission Control Agreement, and
- *Forced Outages^(IMS)* which: 1) were caused by events outside the PTO's system including those Outages which originate in other TO systems, other electric utility systems, or customer equipment, and 2) those Forced Outages^(IMS) which can be demonstrated to have been caused by earthquakes.

4.3. Targets for Availability Performance

The Availability Measure Targets described herein shall be phased in over a period of five years beginning on the ISO Operations Date. The adequacy of each PTO's Availability performance shall be monitored through the use of charts on which are plotted indices reflecting annual Availability performance. These charts, called control charts as shown in Figure 4.3.1, are defined by a horizontal axis with a scale of years and a vertical axis with a scale describing the expected range of magnitudes of the index in question. Annual performance indices shall be plotted on these charts and a series of tests may then be performed to assess the stability of annual performance, shifts in performance and longer term performance trends.

Control charts for each of the following indices shall be developed and utilized to monitor Availability performance for each Voltage Class within each PTO's system:

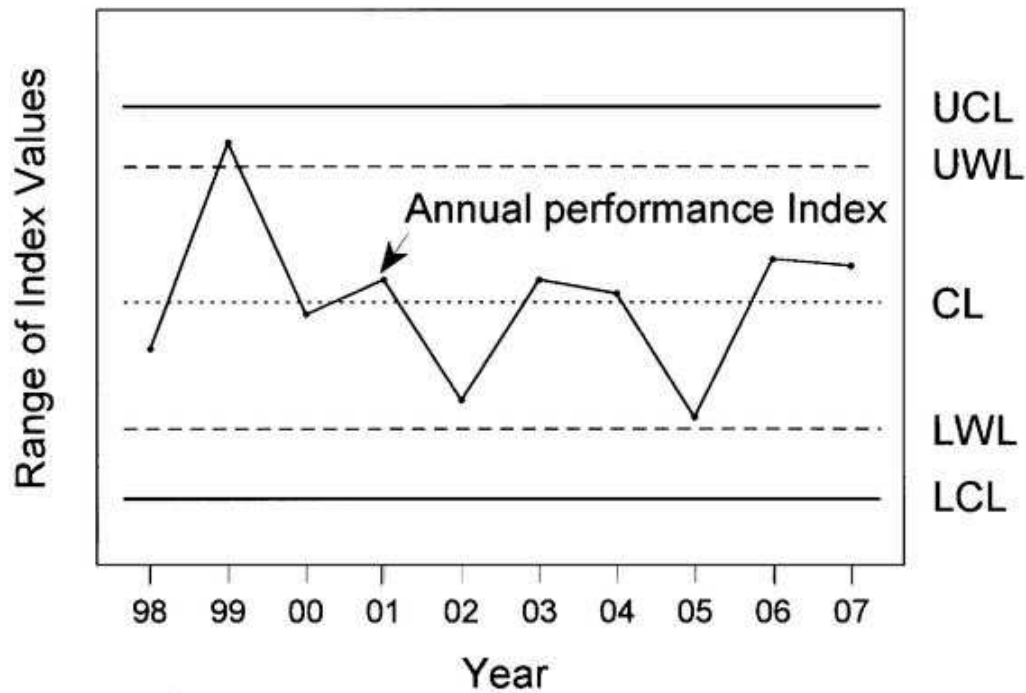


Figure 4.3.1 Sample Control Chart

- *Index 1:* Annual Average Forced Outage ^(IMS) Frequency for All Transmission Line Circuits.
- *Index 2:* Annual Average Accumulated Forced Outage ^(IMS) Duration for those Transmission Line Circuits with Forced Outages ^(IMS).
- *Index 3:* Annual Proportion of Transmission Line Circuits with No Forced Outages ^(IMS).

The control charts incorporate a center line (CL), upper and lower control limits (UCL and LCL, respectively), and upper and lower warning limits (UWL and LWL, respectively). The CL represents the average annual historical performance for a period prior to the current year. The UCL and LCL define a range of expected performance extending above and below the CL. For the annual proportion of Transmission Line Circuits with no Forced Outages ^(IMS), the limits are based on standard control chart techniques for binomial proportion data. For the other two indices, bootstrap resampling techniques are used to determine empirical UCL and LCL at 99.75% and 0.25% percentile values, respectively, for means from the historical data. The bootstrap procedure is described in Section 4.3.2. Similarly, the UWL and LWL define a range of performance intending to cover the percentiles from 2.5% to 97.5%. The bootstrap algorithm is also used to determine these values. Thus, the UCL and LCL will contain about 99.5% of resampling means from the Voltage Class of interest. UWL and LWL will contain about 95% of the resampling means. These limits coincide with the usual choices for control charts when the means are approximately normal. Bootstrap estimation procedures are used here since the sampling means do not follow the Normal distribution model. The bootstrap estimation procedures ensure consistent control chart limits by using a starting base number("seed") for it's random number generator. Accuracy or reduced variances in the control chart limits are attained by using the average control chart limits generated from applying ten repetitions or cycles of the bootstrap sampling method. Collectively, the CL, UCL, LCL, UWL and LWL provide reference values for use in evaluating performance as described in Section 4.3.3.

For the special case where there is a Voltage Class with only one Transmission Line Circuit, individual and moving range control charts should be used for Index 1 and 2. The method used herein for calculating Index 3 is not applicable for those Voltage Classes containing less than six Transmission Line Circuits. Maintenance procedures recommended by the MCC and approved by the ISO Governing Board will be used by the PTOs to calculate Index 1, 2, or 3 where the methods provided herein do not apply . More information on the individual and moving range control charts can be found in the user manuals of the statistical software recommended by the MCC and approved by the ISO Governing Board for use in creating the control charts .

4.3.1. Calculations of Annual Availability Performance Indices for Individual Voltage Classes

Separate annual Availability performance indices shall be calculated for each Voltage Class and PTO as described below utilizing the Availability Measures discussed in Section 4.2.

Annual Average Forced Outage ^(IMS) Frequency for All Transmission Line Circuits (Index 1):

$$F_{vc,k} = \frac{1}{N_k} \sum_{i=1}^{N_k} f_{ik}$$

where

$F_{vc,k}$ = frequency index for the Voltage Class, vc, (units = Forced Outages ^(IMS) /Transmission Line Circuit). The frequency index equals the average (mean) number of Forced Outages ^(IMS) for all Transmission Line Circuits within a Voltage Class for the calendar year k.

N_k = number of Transmission Line Circuits in Voltage Class in calendar year k. See Note 2, Section 4.2.1.

f_{ik} = frequency of Forced Outages ^(IMS) for the ith Transmission Line Circuit as calculated in accordance with Section 4.2.1 for calendar year k.

Annual Average Accumulated Forced Outage ^(IMS) Duration for those Transmission Line Circuits with Forced Outages ^(IMS) (Index 2):

$$D_{vc,k} = \frac{1}{N_{o,k}} \sum_{i=1}^{N_{o,k}} d_{ik}$$

where

$D_{vc,k}$ = duration index for the Voltage Class (units = minutes/Transmission Line Circuit). The duration index equals the average accumulated duration of Forced Outages ^(IMS) for all Transmission Line Circuits within a Voltage Class which experienced Forced Outages ^(IMS) during the calendar year k.

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage ^(IMS) frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.2.1 is greater than zero for the calendar year k. See Note 2, Section 4.2.1.

d_{ik} = accumulated duration of Forced Outages ^(IMS) for the ith Transmission Line Circuit having a Forced Outage ^(IMS) frequency Availability Measure (f_{ik}) greater than zero for calendar year k as calculated in accordance with Section 4.2.1.

Annual Proportion of Transmission Line Circuits with No Forced Outages ^(IMS) (Index 3):

$$P_{vc,k} = \frac{N_k - N_{o,k}}{N_k}$$

where

$P_{vc,k}$ = index for the proportion of Transmission Line Circuits for the Voltage Class with no Forced Outages ^(IMS) for the calendar year k.

N_k = number of Transmission Line Circuits in Voltage Class for calendar year k. See Note 2, Section 4.2.1.

$N_{o,k}$ = number of Transmission Line Circuits in the Voltage Class for which the Forced Outage ^(IMS) frequency Availability Measure (f_{ik}) as calculated in accordance with Section 4.2.1 is greater than zero for the calendar year k. See Note 2, Section 4.2.1.

4.3.2. Development of Limits for Performance Control Charts

The CL, UCL, LCL, UWL and LWL for the three control charts (Annual Average Forced Outage^(IMS) Frequency for All Transmission Line Circuits, Annual Average Accumulated Forced Outage^(IMS) Duration for Transmission Line Circuits with Forced Outages^(IMS), and Annual Proportion of Transmission Line Circuits with No Forced Outages^(IMS)) on which the annual Availability performance indices are to be plotted shall be calculated as described below. The CL, UCL, LCL, UWL and LWL for each of the three control charts shall be determined using continuously recorded Outage^(IMS) data for the ten year period immediately preceding the ISO Operations Date, or immediately preceding the date a TO becomes a PTO. In the event that a PTO does not have reliable, continuously recorded Outage^(IMS) data for this 10 year period, the PTO may determine the control chart limits using data for a shorter period. However, if data for a shorter period are to be used, the PTO shall prepare a brief report to the ISO providing reasonable justification for this modification. This report shall be submitted to the ISO prior to February 1, 1998, or within 30 days after a TO becomes a PTO. The ISO shall periodically review the control chart limits and appropriately modify them when necessary in accordance with Section 8.0, "Revision of ISO Maintenance Standards," of this document.

4.3.2.1. CLs

The calculation of the CLs for each of the three control charts is similar to the calculation of the annual Availability performance indices described in Section 4.3.1 except that the period for which data are to be included in the calculations is expanded from a single calendar year to the ten years, unless a shorter period is justified by the PTO, for the period immediately preceding the ISO Operations Date, or immediately preceding the date a TO becomes a PTO. To account for this change a count of Transmission Line Circuit years is included in the equations as shown below to enable derivation of CLs which represent average performance during a multi-year period.

CL for Annual Transmission Line Circuit Forced Outage^(IMS) Frequency

$$CL_{fvc} = \frac{\sum_{k=1}^Y \sum_{i=1}^{N_k} f_{ik}}{\sum_{k=1}^Y N_k}$$

where

CL_{fvc} = center control line value for the Forced Outage^(IMS) frequencies for each of the Transmission Line Circuits in the Voltage Class for Y years prior to the ISO Operations Date, or the date a TO becomes a PTO.

Y = number of years prior to the ISO Operations Date (or the date a TO becomes a PTO) for which the PTO has reliable, continuously recorded Outage^(IMS) data. Y=10 is preferred.

CL for Annual Accumulated Forced Outage^(IMS) Duration for those Transmission Line Circuits with Forced Outages^(IMS)

$$CL_{dvc} = \frac{\sum_{k=1}^Y \sum_{i=1}^{N_{o,k}} d_{ik}}{\sum_{k=1}^Y N_{o,k}}$$

where

CL_{dvc} = center control line value for accumulated Forced Outage^(IMS) duration for each of the Transmission Line Circuits in the Voltage Class for Y years prior to the ISO Operations Date (or the date a TO becomes a PTO) in which the Forced Outage^(IMS) frequency (f_{ik}) was greater than zero.

CL for Annual Proportion of Transmission Line Circuits with No Forced Outages^(IMS)

$$CL_{Pvc} = \frac{\sum_{k=1}^Y (N_k - N_{o,k})}{\sum_{k=1}^Y N_k}$$

where

CL_{Pvc} = center control line value for the proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages^(IMS) for Y years prior to the ISO Operations Date, or the date a TO becomes a PTO.

4.3.2.2. UCLs, LCLs, UWLs and LWLs

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for Voltage Classes Containing Four or More Transmission Line Circuits with Forced Outages^(IMS) for Five or More Years

The UCLs, UWLs, LWLs, and LCLs for the control charts for each Voltage Class containing four or more Transmission Line Circuits with Forced Outages^(IMS) shall be determined by bootstrap resampling methods as follows: The available historical data for Index 1 and 2 will each be entered into columns. A "seed" is then selected prior to beginning the sampling process. The ISO assigns a number for the "seed" prior to each years development of the control charts. The "seed" allows the user to start the sampling in the same place and get the same results provided the data order hasn't changed. For Index 1, sampling with replacement will occur for the median number of lines per year in a Voltage Class for the time period being evaluated. A sample, the size of which is the median number of all Transmission Line Circuits for the period being evaluated, is taken from the column of actual frequency values for all Transmission Line Circuits. A mean is calculated from this sample and the resulting number will be stored in a separate column. This process, will be repeated 10,000 times in order to create a column of sampling means from the historical data base. The column of sampling means is then ordered from the smallest to largest means. From this column percentiles are determined for a UCL(99.75), a LCL(0.25) a UWL(97.5), and a LWL(2.5). Thus, for one cycle, the limits are determined by resampling from the historical data base, calculating statistics of interest, in this case means, and then estimating appropriate limits from the resampling means. Ten cycles of this same process are necessary to get 10 values each of UCLs, LCLs, UWLs, and LWLs. The average for the ten values of each limit is taken to provide the UCL, LCL, UWL, and LWL values used in analyzing annual performance. The procedure is repeated for Index 2 forming means for the median number of lines with Forced Outages^(IMS) in this Voltage Class for the time period being evaluated. See **Bootstrapping—A Nonparametric Approach to Statistical Inference** (1993) by Christopher Z. Mooney and Robert D. Duval, Sage Publications with ISBN 0-8039-5381-X, and **An Introduction to the Bootstrap** (1993) by Bradley Efron and Robert J. Tibshirani, Chapman and Hall Publishing with ISBN 0-412-04231-2 for further information.

Consider an example to illustrate how the Bootstrap procedure works for one cycle of the ten required. Assume that a Voltage Class has approximately 20 Transmission Line Circuits per year with a history of ten years. Furthermore, assume that about 15 Transmission Line Circuits per year experience Forced Outages. Therefore, there are $10 \times 15 = 150$ Forced Outage^(IMS) durations available for bootstrap sampling. Place these 150 Forced Outage^(IMS) durations in a column, say "outdur"... in a specified order. The order is automatically provided in the bootstrap algorithm developed by the ISO and made available to the PTO. The bootstrap algorithm will sample 15 rows from "outdur" with replacement. That is, any row may, by chance, be sampled more than once. From these 15 values determine the sample mean and place this in another column, say "boot". Repeat this sampling process 10,000 times adding the new means to "boot". The column "boot" now has 10,000 means from samples of size 15 from the original Forced Outage^(IMS) duration data for this Voltage Class. The next step is to locate the appropriate percentiles from these means for use in determining the control chart limits for one cycle. This is accomplished by ordering the column "boot" from smallest to largest mean and restoring these ordered means in "boot". The percentiles which are needed are 99.75% (UCL), 97.50% (UWL), 2.50% (LWL) and 0.25% (LCL). These are easily estimated from the sorted means by finding the associated rows in the column "boot". For example, LWL will be estimated as the average of the 250th and 251st rows in column "boot". Likewise the other limits will be determined. Of course, the CL is the actual mean average for 15 lines over the ten years using the formulas in Section 4.3.2.1. This example is for one cycle. Nine more cycles of this process will establish the more accurate control and warning limits necessary to evaluate a PTO's annual performance.

UCLs, LCLs, UWLs and LWLs for Index 1 and 2 for All Other Voltage Classes

When data for less than four Transmission Line Circuits with Forced Outages^(IMS) are available per year in a Voltage Class for fewer than five years, an exhaustive enumeration of all possible selections with replacement may need to be performed. This is because the number of possible samples for bootstrap resampling will be less than the aforementioned 10,000 resampling frequency used for Voltage Classes containing four or more Transmission Line Circuits with Forced Outages^(IMS) for five or more years. For example, if a Voltage Class has only two Transmission Line Circuits per year for five years, the data base will consist of $2 \times 5 = 10$ accumulated Forced Outage^(IMS) durations assuming both Transmission Line Circuits experience a Forced Outage^(IMS) or more per year. Resampling two values from the column of 10 yields only $10 \times 2 = 100$ possible means. Thus, bootstrap resampling of 10,000 would over-sample the original data $10,000/100 = 100$ times.

For the general case, let M = the number of accumulated Forced Outage^(IMS) durations (or Forced Outage^(IMS) frequencies) from the historical data base. If n is the median number of Transmission Line Circuits per year, there are M*n = U possible enumerated means for this Voltage Class. The procedure to determine the appropriate limits for a Voltage Class is to order the column containing U enumerated means from smallest to largest means. Then, the UCL, LCL, UWL, and LWL are determined from this vector as described above (i.e. at the 99.75, 0.25, 97.5 and 2.5 percentiles, respectively).

UCLs, LCLs, UWLs and LWLs for Index 3 When Number of Lines is > 125

According to standard procedures for proportion control charts for voltage classes where the median number of lines in service is greater than 125 for any given year, the upper and lower control chart limits (UCL, LCL, UWL, and LWL) for the kth year are determined using the normal approximation to the binomial distribution. The formulas are:

$$UCL = CL_{PVC} + 3 S_{PVC,k} \quad LCL = CL_{PVC} - 3 S_{PVC,k}$$

UWL and LWL are calculated by replacing the "3" above with a "2".

and

$$S_{PVC,k} = \sqrt{CL_{PVC} (1 - CL_{PVC}) / N_k}$$

where

$S_{PVC,k}$ = standard deviation for the annual proportion of Transmission Line Circuits in the Voltage Class with no Forced Outages^(IMS) for each (kth) year of the Y years prior to the ISO Operations Date, or the date a TO becomes a PTO. If LCL or LWL is less than zero, they should be set to zero by default.

UCLs, LCLs, UWLs and LWLs for Index 3 when Number of Lines is less than or equal to 125 and greater than or equal to six.

The UCLs, LCLs, UWLs, and LWLs for the control charts for each voltage class shall be based on exact binomial probabilities for those voltage classes having equal to or more than six but less than or equal to 125 median transmission lines per year.

A customized macro and a statistical software package approved by the ISO creates the proportion control charts. The macro determines the control limits and use of the exact binomial or the normal approximation to the binomial for computing the control chart limits. This macro ensures the UCL and LCL contains about 99.5% and the UWL and LWL contains about 95% of the binomial distribution. The percentile values of the UCL, UWL, LWL, and LCL are respectively 99.75%, 97.5%, 2.5%, and 0.25%.

The UCL, UWL, LWL, and LCL are calculated using the following formulas:

$$UCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

$$UWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

$$LWL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

$$LCL = (X_1 + (P_2 - P_1)/(P_3 - P_1))/n$$

Where

- P_2 = A cumulative binomial probability equal to the 0.9975, 0.9750, 0.025, and 0.0025 values used respectively in the UCL, UWL, LWL, and LCL above formulas (i.e. $P_2 = 0.9975$ in the UCL formula and $= 0.025$ in the LWL formula)
- P_1 = A cumulative binomial probability that if not representing the percentile value is representing the percentile value that is less than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g. if $P_1 = 0.74$ and is closest to the 99.75 percentile value and represents the 99 percentile then $P_1 = 0.74$ should be used in the UCL formula).
- P_3 = A cumulative binomial probability that if not representing the percentile value is representing the percentile value that is greater than and closest to the 99.75, 97.50, 2.5, and 0.25 percentile values used respectively in the UCL, UWL, LWL, and LCL formulas (e.g. if $P_3 = 0.82$ and is closest to the 99.75 percentile value and represents the 99.85 percentile then $P_3 = 0.82$ should be used in the UCL formula).
- X_1 = The number of lines with no outages associated with the P_1 cumulative binomial probability values used respectively in the UCL, UWL, LWL, and LCL formulas. (e.g. If $P_1 = 0.74$ and represents the 99th percentile for the case where 78 lines didn't have any outages then $X_1 = 78$ should be used in the UCL formula).
- n = The median number of lines that are in service in a given year. This number remains the same in each of the UCL, UWL, LWL, and LCL formulas

More information on the calculations of the proportion control chart limits is in the current ISO Transmission Facility Availability Performance Monitoring System Handbook.

4.3.3. Evaluation of Availability Performance

The control charts shall be reviewed annually in order to evaluate Availability performance. The annual performance evaluation shall consist of an examination of each of the control charts to determine if one or more of the following four tests indicate a change in performance. The four tests have been selected to enable identification of exceptional performance in an individual year, shifts in longer term performance, and trends in longer term performance.

Tests

- **Test 1:** The index value for the current year falls outside the UCL or LCL.
- **Test 2:** At least v1 consecutive annual index values fall above the CL or v2 consecutive annual index values fall below the CL. The actual values of v1 and v2 will be output from the bootstrap resampling procedures. The choices for v1 and v2 are designed to keep the probability of these events less than one percent.

Table 1. Values of v1 and v2 for Percentiles of the CL in Specified Ranges

Percentile	v1	v2
35 - 39	10	5
40	10	6
41 - 43	9	6
44 - 46	8	6
47 - 48	8	7
49 - 51	7	7
52 - 53	7	8
54 - 56	6	8
57 - 59	6	9
60	6	10
61 - 65	5	10

Thus, for example, if for a particular Voltage Class the percentile of the historical CL is 55%, this says that the CL is located at the 55 percentile of all bootstrap means in the "boot" column. From Table 1, v1=6, and v2=8.

- **Test 3:** At least two out of three consecutive annual index values fall outside the UWL or LWL on the same side of the CL.
- **Test 4:** Six or more values are consecutively increasing or consecutively decreasing.

Therefore, Test 1 is designed to detect a short term change or jump in the average level. Tests 2 and 4 are looking for long term changes. Test 2 will detect a shift up in averages or a shift to a lower level. Test 4 is designed to detect either a trend of continuous increase in the average values or continuous decrease. Test 3 is designed to assess changes in performance during an intermediate period of three years. If Test 3 is satisfied, the evidence is of a decline (or increase) in Availability over a three year period. Together the four tests allow the ISO to monitor the availability performance of a Voltage Class for a PTO.

If none of these tests indicates that a change has occurred, performance shall be considered to be stable and consistent with past performance. If one or more of these tests indicates a change then Availability performance shall be considered as having improved or degraded relative to the performance defined by the control chart. Table 4.3.1 provides a summary of the performance indications provided by the tests. The control chart limits may be updated annually if the last year's Availability performance indices did not trigger any of the four tests. If none of the four tests are triggered, the new limits will be constructed including the last year's data.

The control chart limits may be modified each year to reflect the number of Transmission Line Circuits in service during that year if necessary. However, it is suggested that unless the number of lines changes by more than 30% from the previous year, the use of the median number of lines should continue. Consider an example. Suppose after the control chart has been prepared for a Voltage Class, next year's data arrive with the number of lines 30% higher than the median used in the past. New limits will be generated in order to assess the Availability performance for that year.

For the special case where only one Transmission Line Circuit has a Forced Outage ^(IMS) in a Voltage Class during a year, the assessment process for Index 2 is as follows. If Index 2 for this Transmission Line Circuit does not trigger any of the four tests, no further action is necessary. If, however, one or more of the tests are triggered, then limits for this Transmission Line Circuit for that year should be recalculated based on the historical data for this Transmission Line Circuit alone using an individual and moving range control chart. The only test warranted here is Test 1. More information

on the individual and moving range control charts can be found in the user manuals of the statistical software approved by the ISO for use in creating the control charts

If the ISO deems that the Availability Measure Targets should be modified, they shall be modified in accordance with Section 8.0, "Revision of ISO Maintenance Standards," of this document.

Table 4.3.1 Performance Indications Provided by Control Chart Tests

Control Chart Type	Test		Performance Status Indicated by Test Results	
	Number	Results	Improvement	Degradation
Annual Average Forced Outage ^(IMS) Frequency	1	value is above the UCL		4
		value is below the LCL when LCL>0	4	
	2	v1 or more consecutive values above the CL		4
		v2 or more consecutive values below the CL	4	
	3	2 out of 3 values above the UWL		4
		2 out of 3 values below the LWL	4	
	4	6 consecutive values increasing		4
		6 consecutive values decreasing	4	
Annual Average Accumulated Forced Outage Duration	1	value is above the UCL		4
		value is below the LCL when LCL>0	4	
	2	v1 or more consecutive values above the CL		4
		v2 or more consecutive values below the CL	4	
	3	2 out of 3 values above the UWL		4
		2 out of 3 values below the LWL	4	
	4	6 consecutive values increasing		4
		6 consecutive values decreasing	4	
Annual Proportion of Transmission Line Circuits with No Forced Outages	1	value is above the UCL	4	
		value is below the LCL when LCL>0		4
	2	v1 or more consecutive values above the CL	4	
		v2 or more consecutive values below the CL		4
	3	2 out of 3 values above the UWL	4	
		2 out of 3 values below the LWL		4
	4	6 consecutively increasing values	4	
		6 consecutively decreasing values		4

4.4. Outage^(IMS) Data Reporting

All Outages which interrupt the flow of power on PTO Transmission Facilities under the ISO's Operational Control shall be reported by the PTO to the ISO. Outage^(IMS) reports shall include the date, start time, end time, affected Transmission Facility, and the probable cause of the Outage^(IMS) if known.

5. ISO MAINTENANCE GUIDELINES AND PTO MAINTENANCE PRACTICES

5.1. Introduction

The ISO with due consideration for the recommendations of the Maintenance Coordination Committee shall establish, revise as needed, and maintain guidelines for Transmission Facilities Maintenance as described in Section 5.2 of this document. These ISO Maintenance Guidelines shall be followed by each PTO in preparing a written description of, and updating as necessary, its PTO Maintenance Practices which may be performance-based, time-based, or both, as may be appropriate for each Transmission Facility under the ISO's Operational Control. The PTO Maintenance Practices will provide for consideration of the criteria referenced in Section 14.1 of the TCA, including technological innovations and facility importance.

5.2. ISO Maintenance Guidelines for Preparation of PTO Maintenance Practices

5.2.1. Transmission Line Maintenance

The PTO's Maintenance Practices shall, at a minimum, address the following transmission line Maintenance activities:

a) Patrol/Inspection

- Routine
- Detailed
- Emergency

b) Vegetation Management/Right-of-Way Maintenance

As may be appropriate for the specific facilities and equipment under the ISO's Operational Control, the PTO's Maintenance Practices shall further detail Maintenance activities for various attributes of the transmission lines including, but not limited to:

- Structures: wood pole, lattice steel, tubular steel, and concrete pole
- Guys/Anchors
- Foundations
- Insulators
- Conductor and Shield Wire
- Conductor and Shield Wire Clearances
- Hardware and Fittings
- Disconnects/Pole-top Switches
-
- Encroachments/Unauthorized Attachments
- Underground Transmission Components

5.2.2. Station Maintenance

The PTO's Maintenance Practices shall, at a minimum, address the Maintenance of the following equipment and attributes of Stations:

- Circuit Breakers
- Insulators/Bushings/Arrestors
- Transformers
- Regulator
- Disconnect Switches
- Metering
- Battery Systems
- Reactive Devices

- Relaying
- Communication Facilities
- Station Auxiliary Equipment
- Direct Current Transmission Components
- Structures/Foundations

As may be appropriate for the specific equipment in and configurations of the PTO's Stations under the ISO's Operational Control, the PTO's Maintenance Practices shall further detail various Maintenance activities for the attributes and potential conditions of the Stations including, but not limited to:

- Visual Inspection of/for: fences and grounds, vegetation, clearances, tracking, abnormal heating, cracks/chips, noise, leaks, blown fuses, and bulging of equipment cases
- Oil Containment
- Insulation Mediums
- Equipment Contacts
- Mechanical Timing
- Contamination Control
- Testing and Calibration
- Cooling Systems
- Measuring Devices
- Lubrication and Overhaul of Moving Parts

5.2.3. Descriptions of PTO Maintenance Practices

Each PTO's Maintenance Practices shall include a schedule for any time-based Maintenance activities and a description of conditions that will initiate any performance-based activities. The PTO's Maintenance Practices shall describe the Maintenance methods for each substantial type of component and shall provide any checklists/report forms which may be required for the activity. Where appropriate, the PTO's Maintenance Practices shall provide criteria to be used to assess the condition of a Transmission Facility or component. Where appropriate, the PTO's Maintenance Practices shall specify condition assessment criteria and the requisite response to each condition as may be appropriate for each specific type of component or feature of the Transmission Facilities.

5.3. Review and Adoption of PTO Maintenance Practices

5.3.1. Initial Adoption of PTO Maintenance Practices

5.3.1.1. Submittal of Information by the Prospective PTOs to the ISO

Each prospective PTO shall provide the ISO with information concerning its PTO Maintenance Practices pursuant to Section 5.2 of this Appendix C. This information shall be prepared so as to be easily interpreted by the ISO and shall provide sufficient detail to assess the adequacy and reasonableness of the PTO Maintenance Practices, using the criteria referenced in Section 14.1 of the Transmission Control Agreement.

5.3.1.2. Review of the PTO Maintenance Practices by the ISO

The ISO shall review the information provided pursuant to Section 5.3.1.1 of this Appendix C and may provide to a PTO a recommendation for an amendment to the PTO Maintenance Practices in question by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The disposition of any such recommendation shall be in accordance with Section 5.3.3 of this Appendix C. To the extent there are no recommendations, the PTO Maintenance Practices will be adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.

Any agreement, in respect of PTO Maintenance Practices, reached between the ISO and a prospective PTO prior to the ISO Operations Date shall be adopted by the ISO for purposes of this Section 5.3.1.

5.3.2. Proposals for Amendments to the PTO Maintenance Practices

5.3.2.1. Amendments Proposed by the ISO

The ISO shall periodically review each PTO's Maintenance Practices having regard to the ISO Maintenance Standards, as amended and revised from time to time pursuant to Sections 7 and 8 of this Appendix C. Following such a review, and after considering the Section 348 Criteria, the ISO may recommend an amendment of PTO Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The disposition of any such recommendation shall be in accordance with 5.3.3 of this Appendix C. Except as provided in Section 5.3.3.4 of this Appendix, the effective date shall be no earlier than 30 days from the date of such notice.

5.3.2.2. Amendments Proposed by a PTO

A PTO may provide to the ISO its own recommendation for an amendment to its PTO Maintenance Practices, by means of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. The disposition of any such recommendation shall be in accordance with Section 5.3.3 of this Appendix C. The effective date shall be no earlier than 30 days from the date of such notice.

5.3.3. Disposition of Recommendations

5.3.3.1. If the ISO or a PTO makes a recommendation to amend the PTO Maintenance Practices of a PTO, as contemplated in Sections 5.3.1 or 5.3.2 of this Appendix C, the other Party shall have 30 days to provide a notice to the recommending party, pursuant to Section 26.1 of the Transmission Control Agreement, that it does not agree with the recommended amendment. If it fails to provide such notice of disagreement, the recommended amendment shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO, effective as of the date specified in the notice of the recommended amendment, which date shall be no earlier than 30 days from the date of issuance of such notice of amendment.

5.3.3.2. If a PTO makes a recommendation to amend its PTO Maintenance Practices, and if the ISO provides notice within the 30 days specified in the first paragraph of this Section 5.3.3, pursuant to Section 26.1 of the Transmission Control Agreement, that the ISO, having regard for the Section 348 Criteria, does not agree with the recommended amendment, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If, after such efforts, the PTO and the ISO cannot reach a resolution, the pre-existing PTO Maintenance Practices shall be retained. Either Party may, however, seek further redress through appropriate processes, including the Maintenance Coordination Committee, the ISO Governing Board, and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement. Following the conclusion of the redress processes, the PTO's Maintenance Practices, as altered, if at all, by these processes, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.

5.3.3.3. If the ISO makes a recommendation to amend the PTO Maintenance Practices of a PTO, the PTO Maintenance Practices, as amended pursuant to the ISO recommendation, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO, effective as of the date specified by the ISO in its notice of recommended amendment. If the PTO gives notice of a disagreement within the 30 days specified in the first paragraph of this Section 5.3.3, the PTO and the ISO shall make good faith efforts to reach a resolution relating to the recommended amendment. If a resolution is not reached, either Party may seek further redress through appropriate processes, including the Maintenance Coordination Committee, the ISO Governing Board, and/or the dispute resolution mechanism specified in Section 15 of the Transmission Control Agreement. The PTO may also request, during the initial attempts at resolution and at any stage of the redress processes, a deferral of the ISO recommended amendment, and the ISO shall not unreasonably withhold its consent to such a request, having regard to the Section 348 Criteria. Following the conclusion of the redress processes, the PTO's Maintenance Practices, as altered, if at all, by these processes, shall be deemed adopted by the ISO, pursuant to California Public Utilities Code Section 348, as the PTO Maintenance Practices for that PTO.

5.3.3.4. If the ISO determines in its judgment, after considering the Section 348 Criteria, that prompt action is required to avoid a substantial risk to safety or reliability, it may direct a PTO to implement certain temporary maintenance activities in a period of less than 30 days, by issuing an advisory to the PTO to that effect, by way of a notice delivered in accordance with Section 26.1 of the Transmission Control Agreement. Any such maintenance practice advisories shall specify why implementation solely under Section 5.3.3.3 is not sufficient to avoid a substantial risk to safety or reliability including, where a substantial risk is not imminent or clearly imminent, why prompt action is nevertheless required. If time permits, the ISO shall consult with the relevant PTO before issuing a maintenance practice advisory. Upon receiving such an advisory, a PTO shall implement the temporary maintenance activities in question, as of the date specified by the ISO in its advisory, unless the PTO provides a notice to the ISO, in accordance with Section 26.1 of the Transmission Control Agreement, that the PTO is unable to implement the temporary maintenance activities as specified. Even if the PTO provides such a notice, the PTO shall use its best efforts to implement the temporary maintenance activities as fully as possible. All such maintenance practice advisories shall cease to have effect in 90 days after issuance or such earlier period as the ISO provides in its notice. Renewal or extension of such temporary maintenance requirements beyond 90 days shall require a recommendation process pursuant to Section 5.3.3.2 or Section 5.3.3.3 of this Appendix.

5.3.3.5. Nothing in this Transmission Control Agreement shall be construed to limit the ISO's authority under Public Utilities Code Section 348 to adopt inspection, maintenance, repair, and replacement standards for the transmission facilities under ISO control.

5.4. Qualifications of Personnel

All Maintenance of Transmission Facilities under the ISO's Operational Control shall be performed by persons who, by reason of training, experience and instruction, are qualified to perform the task.

6. MAINTENANCE RECORD KEEPING AND REPORTING

The four elements of the ISO's requirements for Maintenance record keeping and reporting are as follows:

- a) The PTO will maintain records of its Maintenance activities, as set forth in Section 6.1.
- b) The PTO will provide certain Maintenance records to the ISO, as set forth in Section 6.2.
- c) The PTO will allow the ISO to visit Transmission Facilities, as set forth in Section 6.3.
- d) The PTO will make records for Maintenance activities available to the ISO, as set forth in Section 6.4.

In addition, the Maintenance Coordination Committee shall annually review the requirements of this section of the ISO Maintenance Standards and shall seek to standardize reasonable record keeping, reporting and information-sharing requirements sufficient to support ISO regulatory reporting needs.

6.1. The PTO Will Maintain Records of its Maintenance Activities

The PTO shall maintain records demonstrating compliance with each element of the PTO Maintenance Practices. The PTO's Maintenance records shall be maintained for five years, or for one year after specific corrective Maintenance activities identified by the PTO are completed, whichever is longer.

Each PTO's inspection records shall, at a minimum, identify the inspector, the Transmission Facility inspected, the inspection date(s), the findings of the inspection, recommended Maintenance activities, and the priority of the Maintenance recommendations.

Each PTO's Maintenance records shall, at a minimum, identify the person responsible for performing the Maintenance, the date of the Maintenance, the Transmission Facility maintained, and a description of the Maintenance that was performed.

6.2. The PTO Will Provide Certain Maintenance Records to the ISO

By the end of the third year of operation of the ISO, the ISO and PTO's shall develop and implement a standard Maintenance reporting system based on the recommendations of the Maintenance Coordination Committee. Until the standard Maintenance reporting system is implemented, the PTO shall provide the ISO, on an annual basis, records for substantial Maintenance as limited by the following list:

a) Transmission Line Maintenance

- Patrol/Inspection
- Vegetation Management/Right-of-way Maintenance
- Structures: Wood pole, lattice steel, tubular steel, concrete pole
- Insulators (Contamination Control)

b) Station Maintenance

- Circuit Breakers
- Transformers
- Insulators/Bushings/Arrestors (Contamination Control)
- Regulators
- Relaying

If the PTO maintains records in a manner that includes additional information, such records may be submitted in that manner.

6.3. The PTO Will Allow the ISO to Visit Transmission Facilities

The ISO may visit Transmission Facilities in accordance with Section 18.3 of the Transmission Control Agreement.

6.4. The PTO Will Make Records for Maintenance Activities Available to the ISO

The PTO shall make all Maintenance records for a Voltage Class available to the ISO upon the request of the ISO if the annual evaluation of performance per Section 4.3.3 demonstrates degradation in the PTO's Availability performance. Upon identification of degradation, the PTO's reporting of Maintenance data to the ISO shall continue until a subsequent year's annual performance returns to a non-degraded level.

If a review of available records by the ISO indicates inconsistencies from the PTO Maintenance Practices relating to a specific activity, then the ISO may request that the PTO provide further documentation and explanation related to those Maintenance activities.

7. MAINTENANCE COORDINATION COMMITTEE

7.1. Maintenance Coordination Committee Functions

The ISO shall seek to establish and then appropriately convene a Maintenance Coordination Committee for the purposes of periodically conveying information, seeking input from other PTOs and interested stakeholders regarding ISO Maintenance Standards as well as making recommendations with respect to proposed amendments and revisions of the ISO Maintenance Standards.

7.2. Consensus

Although the role of the Maintenance Coordination Committee is advisory in nature, the ISO will strive to achieve a consensus among committee members, and promulgate practices, standards and protocols consistent with relevant laws and regulations.

8. REVISION OF ISO MAINTENANCE STANDARDS

The ISO, PTO's, or any interested stakeholder may submit proposals to amend or revise the ISO Maintenance Standards. Any change proposal shall be submitted to the Maintenance Coordination Committee for consideration in accordance with Section 7.0, "Maintenance Coordination Committee," of this document. Recommendations for revisions of the ISO Maintenance Standards shall be submitted by the Maintenance Coordination Committee to the ISO for approval.

9. INCENTIVES AND PENALTIES

Any incentives and penalties relating to this Appendix shall be established in accordance with the Transmission Control Agreement, the ISO Tariff and ISO Protocols after consultation between the PTO and the ISO, and approval by the FERC. No incentives, penalties or sanctions may be imposed relating to this Appendix unless a Schedule providing for such incentives, penalties or sanctions has first been filed with and made effective by the FERC. Nothing in this Appendix shall be construed as waiving the rights of the PTO to oppose or protest any incentive, penalty or sanction proposed by the ISO to the FERC or the specific imposition by the ISO of any FERC-approved penalty on the PTO.

10. COMPLIANCE WITH OTHER REGULATIONS/LAWS

Each PTO shall maintain its Transmission Facilities that are under the Operational Control of the ISO in accordance with Good Utility Practice, sound engineering judgment, the guidelines as outlined in the Transmission Control Agreement, and all other applicable protocols, laws, and regulations, in order to achieve the Availability Measure Targets set by the ISO.

10.1 SAFETY

It is of paramount importance that the PTO ensure the safety of personnel, and the public in performing these Maintenance duties and that the ISO operate the system in a manner which is compatible with the priority of ensuring safety. The PTO shall ensure the safety of personnel and the public in accordance with jurisdictional agency regulations and ensure the reliability of the system in accordance with CAISO Maintenance Standards. In the event there is conflict between the safety and reliability, the jurisdictional agency regulations for safety shall take precedence.

11. DISPUTE RESOLUTION

Any disputes between the ISO and PTO regarding issues related to the Maintenance, and Availability of Transmission Facilities under the Operational Control of the ISO shall be resolved in accordance with the Section 15 of the Transmission Control Agreement.

TRANSMISSION CONTROL AGREEMENT

APPENDIX D

Master Definitions Supplement

Issued by: Anthony Ivancovich, Senior Regulatory Counsel
Issued on: November 25, 2002

Effective: January 1, 2003

Actual Adverse Tax Action	A plan, tariff provision, operating protocol, action, order, regulation or law issued, adopted, implemented, approved, made effective, taken or enacted by the ISO, the FERC, the IRS or the United States Congress, as applicable, that likely adversely affects the tax- exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO or that, with the passage of time, likely would adversely affect the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO if the affected facilities were to remain under the Operational Control of the ISO; provided, however, no Actual Adverse Tax Action shall result with respect to a Tax Exempt Participating TO that initiates such a plan, tariff provision, operating protocol, action, order, regulation or law; provided further, however, that the immediately preceding proviso shall not include private letter ruling requests or related actions; provided further, that no Actual Adverse Tax Action shall result in connection with Local Furnishing Bonds if the adverse effect on the tax-exempt status of the Local Furnishing Bonds reasonably could be avoided by application of the procedures set forth in Section 4.1.2 or in Section 2.3.2 and Appendix B.
Adverse Tax Action Determination	A determination by a Tax Exempt Participating TO, as supported by (i) an opinion of its (or its joint action agency's) nationally recognized bond counsel, or (ii) the IRS (e.g., through a private letter ruling received by a Tax Exempt Participating TO or its joint action agency), that an Impending Adverse Tax Action or an Actual Adverse Tax Action has occurred.
AGC (Automatic Generation Control)	Generation equipment that automatically responds to signals from the ISO's EMS control in real time to control the power output of electric generators within a prescribed area in response to a change in system frequency, tieline loading, or the relation of these to each other, so as to maintain the target system frequency and/or the established interchange with other areas within the predetermined limits.
Ancillary Services	Regulation, Spinning Reserve, Non-Spinning Reserve, Replacement Reserve, Voltage Support and Black Start together with such other interconnected operation services as the ISO may develop in cooperation with Market Participants to support the transmission of Energy from Generation resources to Loads while maintaining reliable operation of the ISO Controlled Grid in accordance with Good Utility Practice.
Applicable Reliability Criteria	The reliability standards established by NERC, WSCC, and Local Reliability Criteria as amended from time to time, including any requirements of the NRC.
Applicants	Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison Company and any others as applicable.
Approved Maintenance Outage	A Maintenance Outage which has been approved by the ISO through the ISO Outage Coordination Office.

Available Transfer Capacity	For a given transmission path, the capacity rating in MW of the path established consistent with ISO and WSCC transmission capacity rating guidelines, less any reserved uses applicable to the path.
Black Start	The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring power to the ISO Controlled Grid following system or local area blackouts.
Business Day	Monday through Friday, excluding federal holidays and the day after Thanksgiving Day.
Congestion	A condition that occurs when there is insufficient Available Transfer Capacity to implement all Preferred Schedules simultaneously. "Congested" shall be construed accordingly.
Congestion Management	The alleviation of Congestion in accordance with applicable ISO Protocols and Good Utility Practice.
Control Area	An electric power system (or combination of electric power systems) to which a common AGC scheme is applied in order to: i) match, at all times, the power output of the Generating Units within the electric power system(s), plus the Energy purchased from entities outside the electric power system(s), minus Energy sold to entities outside the electric power system, with the Demand within the electric power system(s); ii) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice; iii) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and iv) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.
CPUC	The California Public Utilities Commission, or its successor.
Critical Protective System	Facilities and sites with protective relay systems and Remedial Action Schemes that the ISO determines may have a direct impact on the ability of the ISO to maintain system security and over which the ISO exercises Operational Control.
Day-Ahead Market	The forward market for Energy and Ancillary Services to be supplied during the Settlement Periods of a particular Trading Day that is conducted by the ISO, the PX and other Scheduling Coordinators and which closes with the ISO's acceptance of the Final Day-Ahead Schedule.
Demand	The rate at which Energy is delivered to Loads and Scheduling Points by Generation, transmission or distribution facilities. It is the product of voltage and the in-phase component of alternating current measured in units of watts or standard multiples thereof, e.g., 1,000W=1kW, 1,000kW=1MW, etc.

Eligible Customer	(i) any utility (including Participating TOs, Market Participants and any power marketer), Federal power marketing agency, or any person generating Energy for sale or resale; Energy sold or produced by such entity may be Energy produced in the United States, Canada or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(2) of the Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a state retail access program or pursuant to a voluntary offer of unbundled retail transmission service by the Participating TO.
EMS (Energy Management System)	A computer control system used by electric utility dispatchers to monitor the real time performance of the various elements of an electric system and to control Generation and transmission facilities.
Encumbrance	A legal restriction or covenant binding on a Participating TO that affects the operation of any transmission lines or associated facilities and which the ISO needs to take into account in exercising Operational Control over such transmission lines or associated facilities if the Participating TO is not to risk incurring significant liability. Encumbrances shall include Existing Contracts and may include: (1) other legal restrictions or covenants meeting the definition of Encumbrance and arising under other arrangements entered into before the ISO Operations Date, if any; and (2) legal restrictions or covenants meeting the definition of Encumbrance and arising under a contract or other arrangement entered into after the ISO Operations Date.
End-Use Customer or End-User	A purchaser of electric power who purchases such power to satisfy a Load directly connected to the ISO Controlled Grid or to a Distribution System and who does not resell the power.
Energy	The electrical energy produced, flowing or supplied by generation, transmission or distribution facilities, being the integral with respect to time of the instantaneous power, measured in units of watt-hours or standard multiples thereof, e.g., 1,000 Wh=1kWh, 1,000 kWh=1MWh, etc.
Entitlements	The right of a Participating TO obtained through contract or other means to use another entity's transmission facilities for the transmission of Energy.
Existing Contracts	The contracts which grant transmission service rights in existence on the ISO Operations Date (including any contracts entered into pursuant to such contracts) as may be amended in accordance with their terms or by agreement between the parties thereto from time to time.
Existing Rights	Those transmission service rights defined in Section 2.4.4.1.1 of the ISO Tariff.
Facilities Study Agreement	An agreement between a Participating TO and either a Market Participant, Project Sponsor, or identified principal beneficiaries pursuant to which the Market Participants, Project Sponsor, and identified principal beneficiaries agree to reimburse the Participating TO for the cost of a Facility Study.

Facility Study	An engineering study conducted by a Participating TO to determine required modifications to the Participating TO's transmission system, including the cost and scheduled completion date for such modifications that will be required to provide needed services.
FERC	The Federal Energy Regulatory Commission or its successor.
FIITC (Firm Import Interconnection Transmission Capacity)	The amount of firm transmission capacity in MW associated with transmission facilities owned by a Participating TO or contracted to the Participating TO under an Existing Contract, which allows Generating Units that are not directly interconnected with that Participating TO's transmission or distribution system to deliver Energy to that Participating TO. For each month of the Self-Sufficiency Test Period, FIITC shall include the maximum amount of requirements and bundled power sale capacity purchased by the Participating TO from the transmission owner to which it is physically interconnected during the hour in which the Monthly Peak Load of the Participating TO occurs.
Forced Outage	An Outage for which sufficient notice cannot be given to allow the Outage to be factored into the Day-Ahead Market or Hour-Ahead Market scheduling processes.
FPA	Parts II and III of the Federal Power Act, 16 U.S.C. § 824 et seq., as they may be amended from time to time.
Generating Unit	An individual electric generator and its associated plant and apparatus whose electrical output is capable of being separately identified and metered or a Physical Scheduling Plant that, in either case, is: (a) located within the ISO Control Area; (b) connected to the ISO Controlled Grid, either directly or via interconnected transmission, or distribution facilities; and (c) that is capable of producing and delivering net Energy (Energy in excess of a generating station's internal power requirements).
Generation	Energy delivered from a Generating Unit.
Generator	The seller of Energy or Ancillary Services produced by a Generating Unit.
Good Utility Practice	Any of the practices, methods, and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods, and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety, and expedition. Good Utility Practice is not intended to be any one of a number of the optimum practices, methods, or acts to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Hour-Ahead Market	The forward market for Energy and Ancillary Services to be supplied during a particular Settlement Period that is conducted by the ISO, the PX and other Scheduling Coordinators which opens after the ISO's acceptance of the Final Day-Ahead Schedule for the Trading Day in which the Settlement Period falls and closes with the ISO's acceptance of the Final Hour-Ahead Schedule.
Hydro Spill Generation	Hydro-electric Generation in existence prior to the ISO Operations Date that: i) has no storage capacity and that, if backed down, would spill; ii) has exceeded its storage capacity and is spilling even though the generators are at full output, or iii) has inadequate storage capacity to prevent loss of hydro-electric Energy either immediately or during the forecast period, if hydro-electric Generation is reduced; iv) has increased regulated water output to avoid an impending spill.
Impending Adverse Tax Action	A proposed plan, tariff, operating protocol, action, order, regulation or law that, if issued, adopted, implemented, approved, made effective, taken or enacted by the ISO, the FERC, the IRS or the United States Congress, as applicable, likely would adversely affect the tax-exempt status of any Tax Exempt Debt issued by, or for the benefit of, a Tax Exempt Participating TO if the affected facilities were to remain under the Operational Control of the ISO; provided, however, that with respect to a proposed federal law, such proposed law must first have been approved by (i) one of the houses of the United States Congress and (ii) at least one committee or subcommittee of the other house of the United States Congress; provided further, however, no Impending Adverse Tax Action shall result with respect to a Tax Exempt Participating TO that initiates such a plan, tariff provision, operating protocol, action, order, regulation or law; provided further, however, that the immediately preceding proviso shall not include private letter ruling requests or related actions; provided further, that no Impending Adverse Tax Action shall result in connection with Local Furnishing Bonds if the adverse effect on the tax-exempt status of the Local Furnishing Bonds reasonably could be avoided by application of the procedures set forth in Section 4.1.2 or in Section 2.3.2 and Appendix B.
Interconnection	Transmission facilities, other than additions or replacements to existing facilities that: i) connect one system to another system where the facilities emerge from one and only one substation of the two systems and are functionally separate from the ISO Controlled Grid facilities such that the facilities are, or can be, operated and planned as a single facility; or ii) are identified as radial transmission lines pursuant to contract; or iii) produce Generation at a single point on the ISO Controlled Grid; provided that such interconnection does not include facilities that, if not owned by the Participating TO, would result in a reduction in the ISO's Operational Control of the Participating TO's portion of the ISO Controlled Grid.
Interconnection Agreement	A contract between a party requesting interconnection and the Participating TO that owns the transmission facility with which the requesting party wishes to interconnect.

IRS	The United States Department of Treasury, Internal Revenue Service, or any successor thereto.
ISO (Independent System Operator)	The California Independent System Operator Corporation, a state chartered, nonprofit corporation that controls the transmission facilities of all Participating TOs and dispatches certain Generating Units and Loads.
ISO ADR Procedures	The procedures for resolution of disputes or differences set out in Section 13 of the ISO Tariff, as amended from time to time.
ISO Code of Conduct	For employees, the code of conduct for officers, employees and substantially full-time consultants and contractors of the ISO as set out in Exhibit A to the ISO bylaws; for Governors, the code of conduct for governors of the ISO as set out in Exhibit B to the ISO bylaws.
ISO Control Center	The Control Center established, pursuant to Section 2.3.1.1 of the ISO Tariff.
ISO Controlled Grid	The system of transmission lines and associated facilities of the Participating TOs that have been placed under the ISO's Operational Control.
ISO Governing Board	The Board of Governors established to govern the affairs of the ISO.
ISO Grid Operations Committee	A committee appointed by the ISO Governing Board pursuant to Article IV, Section 4 of the ISO bylaws to advise on additions and revisions to its rules and protocols, tariffs, reliability and operating standards and other technical matters.
ISO Operations Date	The date on which the ISO first assumes Operational Control of the ISO Controlled Grid.
ISO Outage Coordination Office	The office established by the ISO to coordinate Maintenance Outages in accordance with Section 2.3.3 of the ISO Tariff.
ISO Protocols	The rules, protocols, procedures and standards promulgated by the ISO (as amended from time to time) to be complied with by the ISO Scheduling Coordinators, Participating TOs and all other Market Participants in relation to the operation of the ISO Controlled Grid and the participation in the markets for Energy and Ancillary Services in accordance with the ISO Tariff.
ISO Register	The register of all the transmission lines, associated facilities and other necessary components that are at the relevant time being subject to the ISO's Operational Control.
ISO Tariff	The California Independent System Operator Agreement and Tariff, dated March 31, 1997, as it may be modified from time to time.
Load	An end-use device of an End-Use Customer that consumes power. Load should not be confused with Demand, which is the measure of power that a Load receives or requires.
Local Furnishing Bond	Tax-exempt bonds utilized to finance facilities for the local furnishing of electric energy, as described in section 142(f) of the Internal Revenue Code, 26 U.S.C. § 142(f).

Local Furnishing Participating TO	Any Tax-Exempt Participating TO that owns facilities financed by Local Furnishing Bonds.
Local Regulatory Authority	The state or local governmental authority responsible for the regulation or oversight of a utility.
Local Reliability Criteria	Reliability criteria established at the ISO Operations Date, unique to the transmission systems of each of the Participating TOs.
Maintenance Outage	A period of time during which an Operator takes its facilities out of service for the purposes of carrying out routine planned maintenance, or for the purposes of new construction work or for work on de-energized and live transmission facilities (e.g., relay maintenance or insulator washing) and associated equipment.
Market Participant	An entity, including a Scheduling Coordinator, who participates in the Energy marketplace through the buying, selling, transmission, or distribution of Energy or Ancillary Services into, out of, or through the ISO Controlled Grid.
Monthly Peak Load	The maximum hourly Demand on a Participating TO's transmission system for a calendar month, multiplied by the Operating Reserve Multiplier.
Municipal Tax Exempt Debt	An obligation the interest on which is excluded from gross income for federal tax purposes pursuant to Section 103(a) of the Internal Revenue Code of 1986 or the corresponding provisions of prior law without regard to the identity of the holder thereof. Municipal Tax Exempt Debt does not include Local Furnishing Bonds.
Municipal Tax Exempt TO	A Transmission Owner that has issued Municipal Tax Exempt Debt with respect to any transmission facilities, or rights associated therewith, that it would be required to place under the ISO's Operational Control pursuant to the Transmission Control Agreement if it were a Participating TO.
NERC	The North American Electric Reliability Council or its successor.
Nomogram	A set of operating or scheduling rules which are used to ensure that simultaneous operating limits are respected, in order to meet NERC and WSCC operating criteria.
Non-Converted Rights	Those transmission service rights as defined in Section 2.4.4.2.1 of the ISO Tariff.
Non-Participating Generator	A Generator that is not a Participating Generator.
Non-Participating TO	A TO that is not a party to the TCA or for the purposes of Sections 2.4.3 and 2.4.4 of the ISO Tariff the holder of transmission service rights under an Existing Contract that is not a Participating TO.
NRC	The Nuclear Regulatory Commission or its successor.
Operating Procedures	Procedures governing the operation of the ISO Controlled Grid as the ISO may from time to time develop, and/or procedures that Participating TOs currently employ which the ISO adopts for use.

Operational Control	The rights of the ISO under the Transmission Control Agreement and the ISO Tariff to direct Participating TOs how to operate their transmission lines and facilities and other electric plant affecting the reliability of those lines and facilities for the purpose of affording comparable non-discriminatory transmission access and meeting Applicable Reliability Criteria.
Operator	The operator of facilities comprised in the ISO Controlled Grid or Reliability Must-Run Units.
Outage	Disconnection or separation, planned or forced, of one or more elements of an electric system.
Participating Generator	A Generator or other seller of Energy or Ancillary Services through a Scheduling Coordinator over the ISO Controlled Grid and which has undertaken to be bound by the terms of the ISO Tariff.
Participating TO	A party to the TCA whose application under Section 2.2 of the TCA has been accepted and who has placed its transmission assets and Entitlements under the ISO's Operational Control in accordance with the TCA.
Physical Scheduling Plant	A group of two or more related Generating Units, each of which is individually capable of producing Energy, but which either by physical necessity or operational design must be operated as if they were a single Generating Unit and any Generating Unit or Units containing related multiple generating components which meet one or more of the following criteria: i) multiple generating components are related by a common flow of fuel which cannot be interrupted without a substantial loss of efficiency of the combined output of all components; ii) the Energy production from one component necessarily causes Energy production from other components; iii) the operational arrangement of related multiple generating components determines the overall physical efficiency of the combined output of all components; iv) the level of coordination required to schedule individual generating components would cause the ISO to incur scheduling costs far in excess of the benefits of having scheduled such individual components separately; or v) metered output is available only for the combined output of related multiple generating components and separate generating component metering is either impractical or economically inefficient.
PMS (Power Management System)	The ISO computer control system used to monitor the real time performance of the various elements of the ISO Controlled Grid, control Generation, and perform operational power flow studies.

Preferred Schedule	The initial Schedule produced by a Scheduling Coordinator that represents its preferred mix of Generation to meet its Demand. For each Generator, the Schedule will include the quantity of output, details of any Adjustment Bids, and the location of the Generator. For each Load, the Schedule will include the quantity of consumption, details of any Adjustment Bids, and the location of the Load. The Schedule will also specify quantities and location of trades between the Scheduling Coordinator and all other Scheduling Coordinators. The Preferred Schedule will be balanced with respect to Generation, Transmission Losses, Load and trades between Scheduling Coordinators.
Project Sponsor	A Market Participant or group of Market Participants or a Participating TO that proposes the construction of a transmission addition or upgrade in accordance with Section 3.2 of the ISO Tariff.
RAS (Remedial Action Schemes)	Protective systems that typically utilize a combination of conventional protective relays, computer-based processors, and telecommunications to accomplish rapid, automated response to unplanned power system events. Also, details of RAS logic and any special requirements for arming of RAS schemes, or changes in RAS programming, that may be required.
Regulatory Must-Run Generation	Hydro Spill Generation and Generation which is required to run by applicable Federal or California laws, regulations, or other governing jurisdictional authority. Such requirements include but are not limited to hydrological flow requirements, environmental requirements, such as minimum fish releases, fish pulse releases and water quality requirements, irrigation and water supply requirements, or the requirements of solid waste Generation, or other Generation contracts specified or designated by the jurisdictional regulatory authority as it existed on December 20, 1995, or as revised by Federal or California law or Local Regulatory Authority.
Reliability Criteria	Pre-established criteria that are to be followed in order to maintain desired performance of the ISO Controlled Grid under contingency or steady state conditions.
Reliability Must-Run Unit	A Generating Unit which is the subject of the contract between the Generator and the ISO under which, in return for certain payments, the ISO is entitled to call upon the owner to run the unit when required by the ISO for the purposes of the reliable operation of the ISO Controlled Grid.
RTG (Regional Transmission Group)	A voluntary organization approved by FERC and composed of transmission owners, transmission users, and other entities, organized to efficiently coordinate the planning, expansion and use of transmission on a regional and inter-regional basis.
SCADA (Supervisory Control and Data Acquisition)	A computer system that allows an electric system operator to remotely monitor and control elements of an electric system.
Scheduling Coordinator	An entity certified by the ISO for the purposes of undertaking the functions specified in Section 2.2.6 of the ISO Tariff.

Scheduling Point	A location at which the ISO Controlled Grid is connected, by a group of transmission paths for which a physical, non-simultaneous transmission capacity rating has been established for Congestion Management, to transmission facilities that are outside the ISO's Operational Control. A Scheduling Point typically is physically located at an "outside" boundary of the ISO Controlled Grid (e.g., at the point of interconnection between a Control Area utility and the ISO Controlled Grid). For most practical purposes, a Scheduling Point can be considered to be a Zone that is outside the ISO's Controlled Grid.
Self-Sufficiency or Self-Sufficient	A Participating TO for which the sum of its Dependable Generation and its FIITC is greater than or equal to its Monthly Peak Load.
Settlement Account	An account held at a bank situated in California, designated by a Scheduling Coordinator or a Participating TO pursuant to the Scheduling Coordinator's SC Agreement or in the case of a Participating TO, Section 2.2.1 of the TCA, to which the ISO shall pay amounts owing to the Scheduling Coordinator or the Participating TO under the ISO Tariff.
System Emergency	Conditions beyond the normal control of the ISO that affect the ability of the ISO Control Area to function normally including any abnormal system condition which requires immediate manual or automatic action to prevent loss of Load, equipment damage, or tripping of system elements which might result in cascading outages or to restore system operation to meet the minimum operating reliability criteria.
System Planning Studies	Reports summarizing studies performed to assess the adequacy of the ISO Controlled Grid as regards conformance to Reliability Criteria.
System Reliability	A measure of an electric system's ability to deliver uninterrupted service at the proper voltage and frequency.
Tax Exempt Debt	Municipal Tax Exempt Debt or Local Furnishing Bonds.
Tax Exempt Participating TO	A Participating TO that is the beneficiary of outstanding Tax-Exempt Debt issued to finance any electric facilities, or rights associated therewith, which are part of an integrated system including transmission facilities the Operational Control of which is transferred to the ISO pursuant to the TCA.
TCA (Transmission Control Agreement)	The agreement between the ISO and Participating TOs establishing the terms and conditions under which TOs will become Participating TOs and how the ISO and each Participating TO will discharge their respective duties and responsibilities, as may be modified from time to time.
TO (Transmission Owner)	An entity owning transmission facilities or having firm contractual rights to use transmission facilities.
TO Tariff	A tariff setting out a Participating TO's rates and charges for transmission access to the ISO Controlled Grid and whose other terms and conditions are the same as those contained in the document referred to as the Transmission Owners Tariff approved by FERC as it may be amended from time to time.

UDC (Utility Distribution Company)	An entity that owns a Distribution System for the delivery of Energy to and from the ISO Controlled Grid, and that provides regulated retail electric service to Eligible Customers, as well as regulated procurement service to those End-Use Customers who are not yet eligible for direct access, or who choose not to arrange services through another retailer.
Uncontrollable Force	Any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, earthquake, explosion, breakage, or accident to machinery or equipment, any curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities or any other cause beyond a Party's reasonable control and without such Party's fault or negligence.
Voltage Support	Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions.
WEnet (Western Energy Network)	An electronic network that facilitates communications and data exchange among the ISO, Market Participants and the public in relation to the status and operation of the ISO Controlled Grid.
Wheeling Out	Except for Existing Rights and Non-Converted Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located within the ISO Controlled Grid to serve a Load located outside the transmission and distribution system of a Participating TO.
Wheeling Through	Except for Existing Rights and Non-Converted Rights exercised under an Existing Contract in accordance with Sections 2.4.3 and 2.4.4, the use of the ISO Controlled Grid for the transmission of Energy from a Generating Unit located outside the ISO Controlled Grid to serve a Load located outside the transmission and distribution system of a Participating TO.
Withdraw for Tax Reasons or Withdrawal for Tax Reasons	In accordance with Section 3.4 of this Agreement, withdrawal from this Agreement, or withdrawal from the ISO's Operational Control of all or any portion of the transmission lines, associated facilities or Entitlements that were financed in whole or in part with proceeds of the Tax Exempt Debt that is the subject of an Impending Adverse Tax Action or an Actual Adverse Tax Action.
WSCC (Western System Coordinating Council)	The Western Systems Coordinating Council or its successor.

TRANSMISSION CONTROL AGREEMENT

APPENDIX E

Nuclear Protocols

**DIABLO CANYON NUCLEAR POWER PLANT
UNITS 1 & 2**

**REQUIREMENTS FOR OFFSITE
POWER SUPPLY OPERABILITY
REVISION 1**

DCPP 1&2 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

OVERVIEW

The DCPP Operating License and Technical Specifications require two physically independent sources (not necessarily on separate right of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both sources is acceptable. Each of these sources shall be designed to be available in sufficient time following a loss of all DCPP onsite alternating current power supplies and the other offsite electric power circuit. One of these sources shall be designed to be available within a few seconds following a loss-of-coolant accident. For DCPP, the sources available within seconds are the 230 kV grid interface and the second source is the 525 kV grid interface.

During normal operation, each DCPP unit's electrical loads are supplied from the unit's main onsite electrical generator. If the generator is not available, either due to unit shutdown or other reason, the loads (safety related and non-safety related) are transferred to the 230 kV grid. In addition DCPP has a delayed transfer capability to the 525 kV grid. The offsite power source is sometimes referred to as the preferred power supply in the regulatory documents.

The basic requirement for the offsite power supply is that it provides sufficient capacity and capability for safe shutdown and design basis accident mitigation. When this condition is met, the offsite power supply is considered Operable with respect to the DCPP Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If either source of the offsite power system is declared Inoperable, action must be taken to shut down an on-line DCPP unit(s) and, for an off-line unit, to suspend activities as required by the DCPP Operating License and Technical Specifications. DCPP must also perform additional diesel testing. The offsite power system is considered Inoperable if either source is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPP. This level of degradation can be caused by an unstable offsite power system, or any condition, which renders the offsite power unavailable for safe shutdown and emergency purposes.

In specific terms, the offsite power supply voltages (at the DCPP switchyards) must stay within the range of 207 kV to 240 kV and 525 kV to 545 kV under post accident operating conditions. During normal operation, the 230 kV voltage must maintain above 207 kV such that when DCPP transfers its load from the onsite source to the offsite source the voltage does not decrease below 207 kV. During normal operation, the 230 kV voltage at DCPP 230 kV switchyard should meet the 230 kV voltage requirements identified in PG&E Operating Instruction O-23. Otherwise, that offsite power source may be considered Inoperable. Since a design basis accident can result in a unit trip, it is imperative that the trip does not impair the operability of the offsite power system. Therefore, following a trip of a DCPP unit (i.e., the unit breakers open) and assuming the other DCPP unit was already shutdown, the DCPP switchyard voltage must recover to and be maintained at or above 207 kV within 16 seconds following the unit trip. If this condition cannot be met, then the offsite power source is considered Inoperable, and action must be taken to shut down the operating DCPP unit(s). In addition, the 500 kV and 230 kV grid must remain stable if both DCPP units trip.

System Operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially

degraded grid conditions are recognized, assessed and immediately communicated to the DCPD operating staff for Operability determination.

SPECIFIC REQUIREMENTS

Note: This section identifies the operational requirements for the DCPD offsite power supply. These requirements are part of the DCPD design basis and licensing basis and include PG&E System Operating Instruction 0-23 as revised as necessary. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating DCPD unit(s) to shutdown. Failure to meet these requirements must be immediately communicated to the ISO, PG&E and the DCPD operating staff for operability determination. Changes in the operation of the transmission network that conflict with these requirements requires prior approval by PG&E.

- 1. Three transmission lines into the 500 kV DCPD switchyard and two lines into the 230 kV DCPD switchyard are normally in service. Any change that alters the performance capabilities of either offsite source at the applicable switchyard requires prior approval by PG&E (DCPD) and the ISO.

No line may be removed from service at anytime without prior notification to the DCPD Operations Department. At least two independent sources of power, the 500 kV and the 230 kV systems, between the transmission network (grid) and DCPD switchyards shall be available at all times. PG&E System Operating Procedure, 0-23, Operating Instructions for Reliable Transmission Service for Diablo Canyon, provides specific requirements to determine operability of these sources.
- 2. With both Diablo Canyon units off-line, the DCPD 500 kV and 230 kV offsite power source should be capable of providing 130 MVA (i.e. dual unit orderly shutdown) to Diablo Canyon for normal operation, safe shutdown, and design basis accident mitigation.
- 3. The minimum grid voltage at DCPD 230 kV switchyard shall be maintained at or above 230 kV for normal operation with all Los Padres 230 kV elements (See list below) in service. In the event of a system disturbance or line outage that can cause the DCPD voltage to dip below 230 kV, including the trip of a DCPD unit, the grid voltage shall recover to 207 kV or above within 16 seconds.

Los Padres Area Major 230 kV Elements	Major 500 kV Elements
DCPD—Mesa Line	DCPD-Gates Line
Morro Bay—Mesa Line	DCPD-Midway Line #1 & #2 Line
Morro May—DCPD Line	
Morro Bay—Templeton Line	
Morro Bay—Midway Line #1 or #2 Line	
Morro Bay—Gates Line #2 Line	
Largest Los Padres area generator other than DCPD	
DCPD 230 kV capacitor banks	
Mesa 115 kV capacitor banks	

- 4. Planning and operating reliability criteria shall result in plans for the following events without loss of grid stability or availability:
 - a) The loss of two DCPD units.
 - b) The loss of any generating unit on the PG&E grid.
 - c) The loss of any major transmission circuit or intertie on the PG&E grid.
 - d) The loss of any large load or block of load on the PG&E grid.
- 5. The maximum grid voltage at the DCPD 230 kV and 500 kV switchyard s shall be maintained at or below 240 kV and 545 kV, respectively, unless required to preserve transmission network integrity.

6. The 500 kV system shall be maintained between 525 kV and 545 kV. Operation of DCPD is limited between 24.375 kV and 26.25 kV (i.e. 0.975 p.u. and 1.05 p.u.).

PG&E, in coordination with the ISO, shall perform and update system studies based on changing grid conditions (load growth, etc.) to identify critical conditions that could render the DCPD offsite power supply Inoperable. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to effect safe shutdown and to mitigate the effects of an accident at DCPD. This level of degradation can be caused by an unstable offsite power system, or any condition that renders the offsite power supply unavailable for safe shutdown and emergency purposes. Procedures and programs shall be in effect to ensure that the DCPD operating staff is immediately notified of such conditions. Grid conditions that are more severe with respect to DCPD switchyard voltages or otherwise unanalyzed render the offsite power supply Inoperable. DCPD operating staff shall be immediately notified of such conditions. Auditable records of system study results shall be maintained. Study results, including revisions and updates, shall be transmitted via letter to both PG&E (Transmission Planning, Electric System Operations and DCPD) and the ISO. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be transmitted via letter to both PG&E (Transmission Planning, Electric System Operations and DCPD) and the ISO.

System studies shall consider the interconnections between PG&E, and other utilities in the Western Electricity Coordinating Council (WECC) region.

7. In the event of a complete loss of the DCPD offsite power supply (i.e. both the 230 kV and 500 kV grid interfaces) both the ISO and PG&E shall establish the following restoration priorities:
 - a) Highest possible priority shall be given to restoring power to the DCPD switchyards.
 - b) Should incoming lines to the DCPD switchyards be damaged, highest priority shall be assigned to repair and restoration of at least one line into the DCPD switchyards.
 - c) Repair crews engaging in power restoration activities for DCPD shall be given the highest priority for manpower, equipment, and materials.
 - d) Formal programs and procedures shall be in place to effect items a), b), and c) above.
8. Grid frequency shall be maintained at 60 Hertz (nominal). The following operations are initiated for low system frequency conditions:
 - a) At 59.65 Hz, E19 & E20 interruptible customers are tripped.
 - b) PG&E complies with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.
9. Patrol and inspection of PG&E transmission lines shall be performed in accordance with the current CAISO approved PG&E Overhead Electrical Transmission Line Maintenance Practice.
10. Line insulators between the plant and switchyard shall be washed by PG&E on an appropriate wash cycle during the wash season in accordance with the current CAISO approved PG&E Overhead Electrical Transmission Line Maintenance Practice to reduce line outages that may result from flashovers due to possible accumulated contamination.
11. Maintenance, testing and calibration of DCPD switchyard equipment and protective relays shall be performed in accordance with the current CAISO approved PG&E Electrical Station Maintenance Practice.
12. PG&E (DCPD) maintains a safety analysis for DCPD (Section 8.0, Electric Power of DCPD 1&2 Final Safety Analysis Update Report (FSAR)). PG&E (DCPD) is required by 10CFR50.71(e) to submit to the NRC periodic updates to the FSAR. The requirements contained in this Appendix E are documented in the FSAR. Any changes to these requirements, or the Bulk Power Transmission System Reliability criteria used as a basis for compliance with a requirement, shall be transmitted by both the ISO and PG&E (Transmission operator) to PG&E (DCPD) for prior approval.

These Specific Requirements mirror existing operating protocols, equipment, regional and national reliability organization standards and are subject to modification as necessary when new standards, equipment or protocols are adopted or updated.

SONGS 2&3 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY

Revised September 2, 2002

OVERVIEW

The preferred source of electrical power for SONGS electrical loads (safety-related and nonsafety-related) is the **offsite power supply** or 230 kV grid. The offsite power supply is sometimes referred to as the **preferred power supply** in the regulatory documents.

The basic requirement for the offsite power supply is that it provides **sufficient capacity and capability** to safely shut down the reactor and to mitigate certain specified accident scenarios. When this condition is met, the offsite power supply is considered Operable with respect to the SONGS Operating License and Technical Specifications. It is a necessary condition of the Operating License that the offsite power supply be Operable at all times. If the offsite power system is declared Inoperable, action must be taken to shut down an online SONGS unit(s) and, for an offline unit, to suspend activities as required by the SONGS Operating License and Technical Specifications. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to supply electrical loads needed to safely shut down the reactor and to mitigate the effects of an accident at SONGS. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power unavailable to safely shutdown the units or to supply emergency electrical loads.

In specific terms, the offsite power supply voltage (at the SONGS switchyard) must stay within the range of 218 kV to 238 kV under all normal and plant accident (i.e. emergency shutdown or trip) conditions. Otherwise the offsite power supply is considered Inoperable. Since accident scenarios for which the plant is designed can result in a unit trip, it is imperative that the trip not impair the operability of the offsite power system. Therefore, following a trip of a SONGS unit (i.e., the unit breakers open), the SONGS switchyard voltage must recover to and be maintained at or above 218 kV within 2.5 seconds following the trip. If this condition cannot be met, then the offsite power supply is considered Inoperable, and action must be taken to shut down the operating SONGS unit(s). Even though these requirements apply at all times, this condition is primarily of concern when one SONGS unit is online and the other unit offline. If both SONGS units are online and one unit trips (due to an accident or otherwise), the non-tripped unit will provide local voltage support to the SONGS switchyard, and 230 kV system voltage will remain within the required range. In cases where one SONGS unit is online and one unit offline, the offsite power supply must be sufficiently robust to survive a trip of the online unit and meet the SONGS voltage requirements in the post-trip condition. A dual unit trip is not the limiting condition since a plant accident is not postulated simultaneous with a dual unit trip.

System Operating procedures and programs shall be in place to ensure that various system operating conditions (generating unit outages, line outages, system loads, spinning reserve, etc.), including multiple contingency events, are evaluated and understood, such that impaired or potentially degraded grid conditions are recognized, assessed and communicated to the SONGS Control Room for Operability determination.

The SONGS switchyard is made up of the SCE switchyard and the SDG&E switchyard. Unless specifically stated otherwise, SONGS switchyard requirements contained in this document apply to both the SCE switchyard and the SDG&E switchyard.

SPECIFIC REQUIREMENTS

Note 1: This section identifies the operational requirements for the SONGS offsite power supply. These requirements are part of the SONGS design basis and licensing basis. Failure to meet these requirements may render the offsite power supply Inoperable, thus requiring the operating SONGS unit(s) to shutdown. Failure to meet these requirements must be immediately communicated to SCE and the SONGS Control Room for operability determination. Changes in the operation of the transmission network that conflict with these requirements require prior approval by SCE.

Note 2: Specific requirements, procedures, operating bulletins, division orders, and analysis that support or provide the basis for the specific operational requirements may be revised periodically subject to prior approval of the affected parties.

1. Nine transmission lines into the SONGS switchyard are normally in service. Any increase or decrease in the number of lines into the SONGS switchyard requires prior approval of SCE. (Reference 7)

No line may be removed from service for greater than 30 days without prior notification to SCE. At least two independent transmission lines (one from SCE and one from SDG&E) between the transmission network (grid) and SONGS switchyard shall be in service at all times. (References 1, 2, 3, 4, 7, 8)
2. With both San Onofre units off-line, the SONGS offsite power source shall be capable of providing 158 MW and 96 MVAR to San Onofre for normal operation and for shutting down the units during plant Design Basis Accident (DBA) conditions. (References 9, 10)
3. The minimum grid voltage at the SONGS switchyard shall be maintained at or above 218 kV. In the event of a system disturbance that can cause the voltage to dip below 218 kV, including the trip of a SONGS unit, the grid voltage shall recover to 218 kV or above within 2.5 seconds. (References 9, 10, 12, 13, 18)
4. The following initiating events shall not result in the loss of grid stability or availability:
 - a. The loss of a San Onofre Unit (with the other unit already offline), or
 - b. The loss of any generating unit on the SCE and SDG&E grids, or
 - c. The loss of any major transmission circuit or intertie on the SCE and SDG&E grids, or
 - d. The loss of any large load or block of load (e.g., due to a bus section outage) on the SCE and SDG&E grids.(References 2, 3, 4, 8)
5. The maximum grid voltage at the SONGS switchyard shall be maintained at or below 238 kV. (References 10, 11, 18)
6. The normal operating voltage of the SONGS switchyard shall be maintained at 230 kV. The SONGS switchyard voltage shall not exceed 232 kV unless required to preserve transmission network integrity. (References 10, 11, 18)
7. The limiting conditions for SONGS offsite power source operability are defined as follows:
 1. One SONGS unit is off- line, and
 2. One of the critical line (s) outages occurs (see list of the lines below), and
 3. VAR flows north and south of SONGS are above the threshold levels for the existing combined SCE and SDG&E import level as defined by the referenced nomograms in the GCC Operating Procedure: SONGS Voltage (Current revision).

Based on these nomograms and SONGS offline unit's status, if the Grid Control Center or ISO determines that the operating point is outside the applicable derated nomogram line, they shall notify SONGS immediately that a particular transmission line is out of service, and the critical system conditions are sufficient to cause SONGS off site power source to be considered INOPERABLE; i.e., unable to support SONGS voltage at 218 kV if the remaining unit trips. SONGS Control Room will declare the offsite source inoperable (in anticipation of losing the second SONGS unit) and will declare the time period within which the on-line unit will have to initiate shutdown if conditions are not corrected. The time period will be within 1 to 24 hours, based on the SONGS plant and equipment conditions.

List of critical transmission lines/grid conditions:

Critical Line(s) Out In SCE Territory

Palo Verde -Devers 500 kV Line
Ellis- Johanna & Ellis-Santiago 230 kV Lines
Lugo-Serrano & Mira Loma-Serrano 500 kV Lines
Lugo- Mira Loma 2&3 500 kV Lines
Two Midway - Vincent 500 kV Lines
SONGS- Serrano & SONGS - Chino 230 kV Lines

Critical Line(s) Out in SDG&E Territory

Hassayampa-N. Gila 500 kV Line
N. Gila- Imperial Valley 500 kV Line
Imperial Valley- Miguel 500 kV Line
Imperial Valley- Miguel 500 kV Line & Imperial Valley- LaRosita 230 kV Line
SONGS-San Luis Rey 230 kV Tap & SONGS - Mission 230 kV Line

Critical Grid Conditions:

SCE/SDG&E Tie Separation at SONGS:

SCE/SDG&E Tie Open, Unit 3 On-Line (Unit 2 Off-Line)

SCE/SDG&E Tie Open, Unit 2 On-Line (Unit 3 Off-Line)

Systems studies shall be performed and updated based on changing grid conditions (load growth, etc.) to identify critical conditions, such as the above cases, that could render the offsite power supply Inoperable. The offsite power system is considered Inoperable if it is degraded to the point that it does not have the capability to provide electrical support to safe shutdown loads and to mitigate the effects of an accident at SONGS. This level of degradation can be caused by an unstable offsite power system, or any condition which renders the offsite power supply unavailable for safe shutdown and emergency purposes. The following actions are required:

- a. Procedures and programs shall be in effect to ensure that the SONGS Control Room is immediately notified of such conditions.
- b. Grid conditions that are more severe with respect to SONGS switchyard voltage, or are otherwise unanalyzed, render the offsite power supply Inoperable. The SONGS Control Room shall be immediately notified of such conditions.
- c. Auditable records of current system studies shall be made available to SCE as needed to demonstrate compliance with regulatory requirements. Study results, including revisions and updates, shall be formally transmitted to SCE.
- d. Study results and conclusions shall be assessed at least annually and updated, if needed, based on changing grid conditions. Results of the annual assessments shall be formally transmitted to SCE.

(References 1, 2, 19, 21)

System studies shall consider the interconnections between SCE, SDG&E, and other utilities in the Western Electricity Coordinating Council (WECC). (Reference 7)

8. In the event of loss of the SONGS offsite power supply:

Note: SONGS 2 and 3 are required by NRC regulations to be able to safely cope with a loss of all AC power (Station Blackout) for a maximum of four hours. The four hour coping duration is based on the expectation that at least one source of AC power (offsite transmission line or onsite diesel generator) will be restored to the blacked-out unit within the four hours to ensure the proper functioning of systems required for plant safety .

- a. Highest possible priority shall be given to restoring power to the SONGS switchyard. Procedures and training should consider several potential methods of transmitting power from black-start capable units to the SONGS switchyard. This includes such items as nearby gas turbine generators, portable generators, hydro generators, and black-start fossil power plants. (References 15, 26, 28)
- b. Should incoming lines to the SONGS switchyard be damaged, highest priority shall be assigned to repair and restoration of at least one line into the SONGS switchyard.
- c. Repair crews engaging in power restoration activities for SONGS shall be given the highest priority for manpower, equipment, and materials.
- d. Formal programs and procedures shall be in place to effect items a, b, and c above.

(References 14, 15, 16, 17, 26, 27)

9. Grid frequency shall be maintained at 60 Hertz (nominal). A trip of one SONGS unit shall not cause the grid frequency to dip below 59.7 Hertz. SCE and SDG&E comply with the WECC Coordinated Off-Nominal Frequency Load Shedding and Restoration Plan.

Note: System separation between SCE and SDG&E at the SONGS bus tie on low grid frequency mentioned in the previous version of the TCA is being removed from SONGS by mid-2002. Increased load shedding schemes by SDG&E have been implemented which preclude the need for system separation at SONGS bus ties on low frequency.

(References 7, 20)

10. SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report shall be maintained. It is recognized that the SCE and SDG&E Bulk Power Transmission System Reliability Criteria as described in the SONGS 2&3 Updated Final Safety Analysis Report may be revised from time to time. In the event the reliability criteria are revised, a system assessment and/or study (as described under specification 7) shall be performed to determine if the revised reliability criteria adversely impact grid reliability and availability as defined in this specification. Results of the assessment and/or study together with a copy of the revised reliability criteria shall be provided to SCE. Changes in grid operation based on the revised criteria and associated studies shall not be implemented without prior approval of SCE. (Reference 7)
11. Patrol and inspection of SCE and SDG&E transmission lines shall be performed in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice or as required by the NRC plant-operating license, whichever requirement is more stringent. These patrols and inspections are to ensure that the physical and electrical integrity of transmission system components are maintained. (Reference 7)

12. Line insulators on lines which carry power from the plant to the grid shall be washed as required by the NRC plant-operating license or on an appropriate wash cycle in accordance with the current ISO approved Overhead Electric Transmission Line Maintenance Practice, whichever requirement is more stringent. The purpose and frequency of which is proven to prevent line outages that may result from flashovers due to accumulated contamination. (Reference 7)
13. Maintenance, testing and calibration of SCE and SDG&E station equipment and protective relays shall be performed in accordance with the current ISO approved Electrical Station Maintenance Practice or as required by the NRC plant operating license, whichever requirement is more stringent. (Reference 7)
14. Preventive maintenance and testing of SONGS switchyard batteries shall be performed per IEEE 450-1972. Preventive maintenance and testing of SONGS switchyard battery chargers and DC system components shall be performed routinely. (Reference 7, 23)
15. Updates to applicable portions of Section 8.0, Electric Power of the SONGS 2 & 3 Updated Final Safety Analysis Report (UFSAR) shall be provided annually. These updates will be used by SCE to prepare a UFSAR change submittal to the NRC. SONGS is required by 10CFR50.71(e) to submit to the NRC periodic updates to the UFSAR.

REFERENCES

- 1) SONGS 2&3 Operating License and Technical Specifications, Section 3.8, Electrical Power Systems
- 2) 10CFR50 Appendix A, General Design Criterion 17 (GDC-17), Electrical Power Systems
- 3) NUREG 75/087, Standard Review Plan Revision 1, Section 8.2, Offsite Power System
- 4) NUREG 0800, Standard Review Plan Revision 2, Section 8.2, Offsite Power System
- 5) NUREG 0800, Standard Review Plan Revision 2, Branch Technical Position ICSB-11 (PSB), Stability of Offsite Power Systems
- 6) NUREG 0712, SONGS 2&3 Safety Evaluation Report, Section 8.0, Electric Power Systems
- 7) SONGS 2 & 3 Updated Final Safety Analysis Report, Section 8.0, Electric Power
- 8) ANSI/IEEE Std. 765-1983 Preferred Power Supply for Nuclear Power Generating Stations
- 9) SONGS Design Calculation E4C-082, System Dynamic Voltages During Design Basis Accident
- 10) SONGS Design Calculation E4C-090, Auxiliary System Voltage Regulation
- 11) SONGS Design Calculation E4C-092, Short Circuit Studies
- 12) SONGS Design Calculation E4C-098, 4 kV Swgr Protective Relay Setting
- 13) DBD-SO23-120, SONGS Design Basis Document, 6.9KV, 4.16KV and 480V Electrical Systems
- 14) 90051, SONGS Station Blackout Analyses
- 15) NUMARC 87-00 Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors
- 16) Letter from M. O. Medford (SCE) to the Document Control Desk (NRC), dated April 17, 1989, Subject: "Response to 10 CFR 50.63, 'Loss of all Alternating Current Power,' San Onofre Nuclear Generating Station Units 1, 2 and 3"
- 17) Letter from F. R. Nandy (SCE) to the Document Control Desk (NRC), dated May 1, 1990, Subject: "Supplemental Response to 10 CFR 50.63, 'Loss of All Alternating Current Power,' Station Blackout (TAC No. 68599/600), San Onofre Nuclear Generating Station Units 1, 2, and 3"
- 18) System Operating Bulletin 17 Appendix, System Voltage Control for San Onofre Nuclear Generating Station (Current approved revision)
- 19) GCC Operating Procedure: SONGS Voltage (Current approved revision)
- 20) System Operating Bulletin 113, San Onofre 220 kV System Separation (Current approved revision)
- 21) Regulatory Guide 1.93, Availability of Electric Power Sources
- 23) SCE Division Order 60.20, Storage Batteries (Current approved revision)
- 26) System Operating Bulletin 1-A, Thermal Station Start-up and Power System Restoration (Current approved revision)
- 27) System Operating Bulletin 254, Emergency Orders—San Onofre Nuclear Generating Station 220 kV (Current approved revision)
- 28) SDG&E Control Procedure 1150, Capacity & Energy Emergencies—SDG&E System Emergencies (Current approved revision)

TRANSMISSION CONTROL AGREEMENT

APPENDIX F

NOTICES

Issued by: Anthony Ivancovich, Senior Regulatory Counsel
Issued on: November 25, 2002

Effective: January 1, 2003

NOTICES

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Issued by: Anthony Ivancovich, Senior Regulatory Counsel
Issued on: September 7, 2004

Effective: Upon notice after November 1, 2004

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[EXHIBIT B-1 \(TO PG&E APPENDIX B\) Path 15 Operating Instructions For Existing Encumbrances Across the Path 15 Interface April 1, 2003, Revision 1](#)
[EXHIBIT B-1 \(TO PG&E APPENDIX B\)](#)
[ATTACHMENT 1](#)
[CALIFORNIA ISO PATH 15 ATC DETERMINATION METHODOLOGY](#)
[TRANSMISSION CONTROL AGREEMENT APPENDIX D Master Definitions Supplement](#)
[TRANSMISSION CONTROL AGREEMENT APPENDIX E Nuclear Protocols](#)
[DIABLO CANYON NUCLEAR POWER PLANT UNITS 1 & 2 REQUIREMENTS FOR OFFSITE POWER SUPPLY OPERABILITY REVISION 1](#)
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Exhibit 10.9

OPERATING AGREEMENT

Between

STATE OF CALIFORNIA
DEPARTMENT OF WATER RESOURCES

And

PACIFIC GAS AND ELECTRIC COMPANY

THIS AGREEMENT HAS BEEN FILED WITH AND APPROVED BY THE CALIFORNIA PUBLIC UTILITIES COMMISSION ("COMMISSION") FOR USE BETWEEN THE STATE OF CALIFORNIA DEPARTMENT OF WATER RESOURCES ("DWR") AND PACIFIC GAS AND ELECTRIC COMPANY ("UTILITY").

Original Execution Date: April 17, 2003

Amended Execution Date: November 12, 2004(1)

Date of Commission Approval: January 3, 2005

Effective Date: December 22, 2004

(1) Pursuant to D.04-10-020.

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OPERATING AGREEMENT

This **OPERATING AGREEMENT** (this "Agreement") is between the State of California Department of Water Resources ("DWR"), acting solely under the authority and powers granted by AB1X, codified as Sections 80000 through 80270 of the Water Code, and not under its powers and responsibilities with respect to the State Water Resources Development System, and Pacific Gas and Electric Company, a California corporation ("Utility"). DWR and Utility are sometimes collectively referred to herein as the "Parties" and individually referred to as a "Party." Unless otherwise noted, all capitalized terms shall have the meanings set forth in Article I of this Agreement.

RECITALS

WHEREAS, under the Act, DWR has entered into a number of long-term power purchase agreements for the purpose of providing the net short requirements to the retail ratepayers of the State's electrical corporations, including Utility; and

WHEREAS, the Contract Allocation Order of the Commission provides that such long-term power purchase agreements are to be operationally allocated among the State's electrical corporations, including Utility, solely for the purpose of causing the State's electrical corporations to perform certain specified functions on behalf of DWR, as DWR's limited agent, including dispatching, scheduling, billing and settlements functions, and to sell surplus energy, all as such functions relate to those certain power purchase agreements that are operationally allocated to each electrical corporation under the Contract Allocation Order; and

WHEREAS, DWR wishes to provide for the performance of such functions under the Allocated Contracts by Utility on behalf of DWR in accordance with such long-term power purchase agreements as provided in this Agreement; and

WHEREAS, consistent with the Contract Allocation Order, DWR will retain legal and financial obligations, together with ongoing responsibility for any other functions not explicitly provided in this Agreement to be performed by Utility, with respect to each of the Allocated Contracts and it is the intent of DWR and the Utility that the provisions of this Agreement will not constitute an "assignment" of the Allocated Contracts or Interim Contracts to Utility.

WHEREAS, consistent with the Interim Contract Order of the Commission, DWR expects to enter into certain Interim Contracts prior to January 1, 2003 and DWR wishes to provide for the administration of such Interim Contracts by Utility.

NOW, THEREFORE, in consideration of the mutual obligations of the Parties, the Parties agree as follows:

ARTICLE I DEFINITIONS

Section 1.01. *Definitions.* The following terms shall have the respective meanings in this Agreement:

The following terms, when used herein (and in the attachments hereto) with initial capitalization, shall have the meaning specified in this Section 1.01. Certain additional terms are defined in the attachments hereto. The singular shall include the plural and the masculine shall include the feminine and neuter, and *vice versa*. "Includes" or "including" shall mean "including without limitation." References to a section or attachment shall mean a section or attachment of this Agreement, as the case may be, unless the context requires otherwise, and reference to a given agreement or instrument shall be a reference to that agreement or instrument as modified, amended, supplemented or restated through the date as of which such reference is made (except as otherwise specifically provided herein).

Unless the context otherwise requires, references to Applicable Laws or Applicable Tariffs shall be deemed references to such laws or tariffs as they may be amended, replaced or restated from time to time. References to the time of day shall be deemed references to such time as measured by prevailing Pacific Time.

" *Act* " means Chapter 4 of Statutes of 2001 (Assembly Bill 1 of the First 2001-02 Extraordinary Session) of the State of California, as amended.

" *Agreement* ", means this Operating Agreement, together with all attached Schedules, Exhibits and Attachments, as such may be amended from time to time as evidenced by a written amendment executed by the Parties.

" *Allocated Contracts* " means the long-term power purchase agreements operationally allocated to Utility under the Contract Allocation Order, without legal and financial assignment of such agreements to Utility, as provided in Schedule 1 attached hereto.

" *Allocated Power* " means all power and energy, including the use of such power or energy as ancillary services, delivered or to be delivered under the Contracts.

" *Applicable Commission Orders* " means such rules, regulations, decisions, opinions or orders as the Commission may lawfully issue or promulgate from time to time, which relate to the subject matter of this Agreement.

" *Applicable Law* " means the Act, Applicable Commission Orders and any other applicable statute, constitutional provision, rule, regulation, ordinance, order, decision or code of a Governmental Authority.

" *Applicable Tariffs* " means Utility's tariffs, including all rules, rates, schedules and preliminary statements, governing electric energy service to Utility's customers in its service territory, as filed with and approved by the Commission and, if applicable, the Federal Energy Regulatory Commission.

" *Assign(s)* " shall have the meaning set forth in Section 14.01.

" *Bonds* " shall have the meaning set forth in the Rate Agreement.

" *Bond Charges* " shall have the meaning set forth in the Rate Agreement.

" *Business Day* " means the regular Monday through Friday weekdays that are customary working days, excluding holidays, as established by Applicable Tariffs.

" *Commission* " means the California Public Utilities Commission.

" *Confidential Information* " shall have the meaning set forth in Section 11.01(c).

" *Contracts* " means the Allocated Contracts and the Interim Contracts.

" *Contract Allocation Order* " means Decision 02-09-053 of the Commission, issued on September 19, 2002, as such Decision may be modified, revised, amended, supplemented or superseded from time to time by the Commission.

" *DWR Power* " shall have the same meaning set forth in the Servicing Arrangement with such amendments to incorporate the Settlement Principles for Remittances and Surplus Revenues as provided in Exhibit C of this Agreement.

" *DWR Revenues* " means those amounts required to be remitted to DWR by Utility in accordance with this Agreement and as further provided in the Servicing Arrangement.

" *Effective Date* " means the effective date in accordance with Section 14.13, as such date is set forth on the cover page hereof.

" *Fund* " means the Department of Water Resources Electric Power Fund established by Section 80200 of the California Water Code.

" *Good Utility Practice* " means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice does not require the optimum practice, method, or act to the exclusion of all others, but rather is intended to include acceptable practices, methods, or acts generally accepted in the Western Electric Coordinating Council region.

" *Governmental Authority* " means any nation or government, any state or other political subdivision thereof, and any entity exercising executive, legislative, judicial, regulatory or administrative functions of or pertaining to a government, including the Commission.

" *Governmental Program* " means any program or directive established by Applicable Law which directly or indirectly affects the rights or obligations of the Parties under this Agreement and which obligates or authorizes DWR to make payments or give credits to customers or other third parties under such programs or directives.

" *ISO* " means the California Independent System Operator Corporation.

" *Interim Contract Order* " means Decision 02-08-071 of the Commission, issued on August 22, 2002, as such Decision may be amended or supplemented from time to time by the Commission.

" *Interim Contracts* " mean the power purchase or exchange arrangements between DWR and various Suppliers entered into by DWR at the request of Utility and consistent with the Interim Contract Order, as listed in Schedule 2 attached hereto.

" *Order* " means Decision 02-12-069 of the Commission, issued on December 19, 2002 as such decision may be amended or supplemented from time to time by the Commission.

" *Power Charges* " shall have the meaning set forth in the Rate Agreement.

" *Priority Long Term Power Contract* " shall have the meaning set forth in the Rate Agreement.

" *Rate Agreement* " means the Rate Agreement between DWR and the Commission adopted by the Commission on February 21, 2002 in Decision 02-02-051.

" *Remittance* " means a payment by Utility to DWR or its Assign(s) in accordance with the Servicing Arrangement.

" *Servicing Arrangement* " means the Servicing Order as specified in Commission Decision 02-12-072, dated December 19, 2002, as may be modified from time to time.

" *Supplier* " means those certain third parties who are supplying power pursuant to the Contracts.

" *Term* " means term provided in Section 2.05 hereof.

" *URG* " means utility-retained generation, including without limitation Utility's portfolio of generation resources and power purchase agreements prior to or after the Effective Date by Utility.

Section 1.02. *Undefined Terms.* Capitalized terms not otherwise defined in Section 1.01 herein shall have the meanings set forth in the Act or the Servicing Arrangement.

ARTICLE II
OPERATIONAL ALLOCATION OF POWER PURCHASE AGREEMENTS;
MANAGEMENT OF THE CONTRACTS; ALLOCATED POWER; TERM

Section 2.01. *Operational Allocation and Management of Power Purchase Agreements.* On behalf of DWR, as its limited agent, Utility will perform certain day-to-day scheduling and dispatch functions, billing and settlements and surplus energy sales and certain other tasks with respect to the Allocated Contracts and each Interim Contract, as more fully set forth in this Agreement.

As further provided in Contract Administration and Performance Test Monitoring Protocols set forth in Exhibit E, DWR will continue to monitor and audit the Supplier performance under the Contracts. Upon development of a mutually agreeable plan, Utility will monitor the performance of Suppliers, as further provided in Exhibit E, subject, however, to DWR's right but not the obligation to audit and monitor all functions contemplated to be performed by Utility, all as further provided in this Agreement.

Section 2.02. *Standard of Contract Management.*

- (a) Utility agrees to perform the functions specified in this Agreement relating to the Allocated Contracts and prior to novation, and Interim Contracts in a commercially reasonable manner, exercising Good Utility Practice, and in a fashion reasonably designed to serve the overall best interests of retail electric customers. Utility shall provide to DWR such information specifically provided in Exhibit F hereto to facilitate DWR's verification of Utility's compliance with this Section 2.02.
- (b) To the extent requested by Utility, DWR shall provide evidence in Commission proceedings describing Utility's and DWR's performance, rights and obligations under this Agreement.
- (c) DWR acknowledges the Commission's exclusive authority over whether the Utility has managed Allocated Power available under the Contracts in a just and reasonable manner and DWR and Utility agree that none of the provisions of this Agreement shall be interpreted to reduce, diminish, or otherwise limit the scope of any Commission authority or to give DWR any authority over such matters. In addition, the Parties acknowledge that DWR is not subject to the Commission's jurisdiction, and the Parties agree that none of the provisions of this Agreement, including Section 13.04 herein, shall be interpreted to subject DWR to the Commission's jurisdiction or authority.
- (d) The Utility acknowledges DWR's separate and independent right to evaluate and enforce Utility's commercial performance under this Agreement.
- (e) Utility agrees to provide any information not otherwise required herein that is reasonably necessary to allow DWR to exercise its rights in subsection (d) above, provided that all such information shall be used solely for the purposes of exercising such rights.

Section 2.03. *Good Faith.* Each Party hereby covenants that it shall perform its actions, obligations and duties in connection with this Agreement in good faith.

Section 2.04. *DWR Power.* During the term of this Agreement, the electric power and energy, including but not limited to capacity, and output, or any of them from the Contracts delivered to retail end-use customers in Utility's service area shall constitute DWR Power for all purposes of the Servicing Arrangement. Utility shall arrange for transmission service to accommodate surplus sales to the extent that transmission service is available and cost effective, all as further provided in Exhibit A.

Section 2.05. *Term.*

- (a) The Term of this Agreement shall commence on the Effective Date and shall terminate on the earlier of (a) the termination of the Servicing Arrangement, or (b) the termination of this Agreement by DWR upon ninety days' written notice to Utility, or (c) upon consultation with

the Commission, the termination of the Agreement by DWR upon reasonable written notice to Utility no shorter than 30 days, or (d) pursuant to Article VII hereof, the termination of this Agreement by a non-defaulting Party after an Event of Default. In addition, this Agreement will terminate as to each Contract that terminates in accordance with its terms. DWR agrees to notify Utility as to the termination of each Contract as provided in Section 5.01(e) hereof.

- (b) If an event occurs which has the effect of materially altering and materially adversely impacting the economic position of the Parties or either of them under this Agreement, then the affected Party may, by written notice, request that the Commission approve amendments to this Agreement or other arrangements incidental to this Agreement as necessary to preserve or restore the economic position under this Agreement held by the affected Party immediately prior to such event. Such notice shall describe the event and shall include reasonable particulars as to the manner and extent to which the economic position of the Party giving notice has been adversely affected.

ARTICLE III LIMITED AGENCY / NO ASSIGNMENT

Section 3.01. *Limited Agency.* Utility is hereby appointed as DWR's agent for the limited purposes set forth in this Agreement. Utility shall not be deemed to be acting, and shall not hold itself out, as agent for DWR for any purpose other than those described in this Agreement. Utility's duties and obligations shall be limited to those duties and obligations that are specified in this Agreement.

Section 3.02. *No Assignment.* DWR shall remain legally and financially responsible for performance under each of the Contracts and shall retain liability to the counterparty for any failure of Utility to perform the functions referred to in this Agreement on behalf of DWR as its limited agent, under such Contracts in accordance with the terms thereof. It is the intent of DWR and Utility that the provisions of this Agreement shall not constitute or result in an "assignment" of the Allocated Contracts in any respect.

ARTICLE IV LIMITED DUTIES OF UTILITY

Section 4.01. *Limited Duties of Utility as to the Contracts.* During the Term of this Agreement, Utility shall:

- (a) On behalf of DWR, as its limited agent, perform the day-to-day scheduling and dispatch functions, including day-ahead, hour-ahead and real time trading, scheduling transactions with all involved parties, under the Allocated Contracts, perform billing and settlements functions and obtain relevant information for these functions such as transmission availability and others, with respect to the Allocated Contracts set forth in Schedule 1 hereto, all as more specifically provided in the Operating Protocols attached hereto as Exhibit A;
- (b) On behalf of DWR, as its limited agent, enter into transactions for the purchase (or sale, as the case may be) of gas, gas transmission services, gas storage services and financial hedges, and perform the operational and administrative responsibilities for such purchases under gas tolling provisions under the Allocated Contracts, including the review of fuel plans and consideration of alternative fuel supply, all as more specifically provided in the Fuel Management Protocols attached hereto as Exhibit B;
- (c) On behalf of DWR, as its limited agent, perform all necessary billing and settlement functions under the Allocated Contracts in accordance with the terms of the applicable Allocated Contracts. In addition, perform all necessary billing and settlement functions related to DWR Revenues and remit DWR Revenues to DWR, consistent with the Settlement Principles for

Remittances and Surplus Revenues attached hereto as Exhibit C and the Servicing Arrangement;

- (d) Assume financial responsibility for the ISO charges listed on Exhibit D attached hereto;
- (e) On behalf of DWR, as its limited agent, upon development of a mutually agreeable plan, monitor the performance of Suppliers under the Allocated Contracts and undertake the administration of the Allocated Contracts, as more specifically provided in the Contract Administration and Performance Monitoring Protocols attached hereto as Exhibit E;
- (f) Provide to DWR the necessary information required by DWR as more specifically provided in the DWR Data Requirements From Utility attached hereto as Exhibit F to facilitate DWR's continued performance of financial obligations related to Allocated Contracts and to facilitate DWR's verification, audit and monitoring related to the Allocated Contracts and reporting requirements set forth in Applicable Laws or agreements;
- (g) At all times in performing its obligations under this Agreement (i) comply with the provisions of each of the Allocated Contracts, (ii) follow Good Utility Practice, and (iii) comply with all Applicable Laws and Applicable Commission Orders;
- (h) Appoint a primary and secondary contact person, as set forth in Schedule 2 hereto, to coordinate the responsibilities listed in this Section 4.01; and
- (i) On behalf of DWR, as its limited agent, make surplus energy sales as more specifically provided in this Agreement; and
- (j) Prior to novation of the Interim Contracts by Utility in accordance with the terms of each such Interim Contract, comply with the provisions listed in paragraphs (a) through (i) of this Section 4.01, in each case substituting the defined term Interim Contract(s) for the term Allocated Contract(s).

Provided, however, in the event that DWR fails to provide or provides inaccurate information which results in Utility's non-compliance with its obligations under this Agreement, the resulting non-compliance by Utility shall not constitute an Event of Default under Section 7.01 hereof.

Section 4.02. *Dispatch or Sale of Allocated Power.* Subject to any existing or new ISO tariff provisions that may affect the dispatch of such Contracts, Allocated Power from all Contracts shall be dispatched or sold, as the case may be, by Utility pursuant to the Operating Protocols attached hereto as Exhibit A.

Section 4.03. *DWR Revenues.* DWR Revenues shall be accounted and remitted to DWR consistent with the principles provided in the Settlement Principles for Remittances and Surplus Revenues attached hereto as Exhibit C and the provisions of the Servicing Arrangement. Unless otherwise specifically provided in this Agreement, Utility will not be required at any time to advance or pay any of its own funds in the fulfillment of its responsibilities under this Agreement.

Section 4.04. *Ownership of Allocated Power.* Notwithstanding any other provision herein, and in accordance with the Act and Section 80110 of the California Water Code, Utility and DWR agree that DWR shall retain title to all Allocated Power, including DWR Power. In accordance with the Act and Section 80104 of the California Water Code, upon the delivery of Allocated Power to Utility's customers, those customers shall be deemed to have purchased that power from DWR, and payment for such sale shall be a direct obligation of such customer to DWR. In addition, Utility and DWR agree that DWR shall retain title to any surplus Allocated Power sold by Utility as limited agent to DWR as provided in this Agreement.

**ARTICLE V
DUTIES OF DWR**

Section 5.01. *Duties of DWR.* Consistent with the Contract Allocation Order, during the Term of this Agreement, DWR shall:

- (a) Remain legally and financially responsible under each of the Contracts and cooperate with Utility in the transition from DWR to Utility the performance of the functions provided in this Agreement;
- (b) Assume legal and financial responsibilities and enter into or facilitate Utility's entering into transactions as DWR's limited agent, for the purchase (or sale, as the case may be) of gas, gas transmission services, gas storage services and financial hedges, and timely consent to or approve the Utility's performance of the operational and administrative responsibilities for such purchases under gas tolling provisions under the Allocated Contracts, including the review of fuel plans and consideration of alternative fuel supply, all as more specifically provided in the Fuel Management Protocols attached hereto as Exhibit B;
- (c) Pay invoices to the Suppliers and perform all necessary verification, audit and monitoring of the billing and settlement functions to be performed on DWR's behalf, as its limited agent, by Utility relating to the Contracts and prior to novation, the Interim Contracts. In addition, perform all necessary verification, audit and monitoring of the billing and settlement functions to be performed on DWR's behalf, as its limited agent, by Utility related to DWR Revenues, consistent with the principles set forth in the Settlement Principles for Remittances and Surplus Revenues attached hereto as Exhibit C;
- (d) Until such time as a mutually agreed upon plan may be entered into with Utility and approved by the Commission, and no earlier than January 1, 2004, continue to monitor the performance of Suppliers and conduct certain contract administration duties under the Allocated Contracts, all as more specifically provided in the Contract Administration and Performance Monitoring Protocols attached hereto as Exhibit E. In addition, continue to perform all other administrative functions related to Contracts not explicitly provided in this Agreement to be performed by Utility on behalf of DWR, as its limited agent;
- (e) Upon the termination of any Contract, submit in writing to Utility appropriate Schedules and Attachments to Exhibit A amended to reflect the termination of any Contract. Such amended Schedules and Attachments shall become effective only upon the effective date of the termination of such Contract. Provided, however, rights or obligations of the Parties that arise or relate to Utility's performance of its duties under this Agreement in respect of any terminated Contract shall survive until the expiration of any such right or obligation; and
- (f) Appoint a primary and secondary contact person, as set forth in Schedule 3 hereto, to coordinate the responsibilities listed in this Section 5.01.

**ARTICLE VI
SPECIAL CONTRACT TERMS**

Section 6.01. *Special Contract Terms.* In addition to the obligations set forth in this Agreement, Utility agrees to comply with the terms and provisions applicable to the Interim Contracts as set forth in Schedule 2 hereto.

**ARTICLE VII
EVENTS OF DEFAULT**

Section 7.01. *Events of Default.* The following events shall constitute "Events of Default" under this Agreement:

- (a) any material failure by a Party to pay any amount due and payable under this Agreement that continues unremedied for five (5) Business Days after the earlier of the day the defaulting Party receives written notice thereof from the non-defaulting Party; or
- (b) any material failure by Utility to schedule and dispatch Contracts, consistent with the principles set forth in Exhibit A; or
- (c) any failure (except as provided in (a) or (b)) by a Party to duly observe or perform in any material respect any other covenant or agreement of such Party set forth in this Agreement, which failure continues unremedied for a period of 15 calendar days after written notice of such failure has been given to such Party by the non-defaulting Party; or
- (d) any material representation or warranty made by a Party shall prove to be false, misleading or incorrect in any material respect as of the date made; or
- (e) an Event of Default (as defined under the Servicing Arrangement) shall have occurred and is continuing under the Servicing Arrangement.

Section 7.02. *Consequences of Utility Event of Default.* Upon any Event of Default by Utility, DWR may, in addition to exercising any other remedies available under this Agreement or under Applicable Law, (i) terminate this Agreement in whole or in part; and (ii) apply in an appropriate forum for sequestration and payment to DWR or its Assign(s) of DWR Revenues or for specific performance of the functions related to the Contracts to be performed by Utility on behalf of DWR, as its limited agent, as provided in this Agreement.

Section 7.03. *Consequences of DWR Event of Default.* Upon an Event of Default by DWR (other than an Event of Default under 7.01 (a)), Utility shall request that the Commission terminate this Agreement in whole or in part, Section 2.05 notwithstanding.

Section 7.04. *Remedies.* Subject to Article XIII of this Agreement, upon any Event of Default, the non-defaulting Party may exercise any other legal or equitable right or remedy that may be available to it under applicable law or under this Agreement.

Section 7.05. *Remedies Cumulative.* Except as otherwise provided in this Agreement, all rights of termination, cancellation, or other remedies in this Agreement are cumulative. Use of any remedy shall not preclude any other remedy available under this Agreement.

Section 7.06. *Waivers.* None of the provisions of this Agreement shall be considered waived by either Party unless the Party against whom such waiver is claimed gives such waiver in writing. The failure of either Party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights for the future, but the same shall continue and remain in full force and effect. Waiver by either Party of any default by the other Party shall not be deemed a waiver of any other default.

**ARTICLE VIII
PAYMENT OF FEES AND CHARGES**

Section 8.01. *Utility Fees and Charges.* As noted in the Contract Allocation Order, the details of the amount and recovery of administrative costs to Utility associated with the Contracts are expected to be considered in another Commission proceeding. As such, the Parties agree that the administrative

costs to Utility will be recovered pursuant to such Commission proceeding. Utility shall enter the cost of such fees and charges in its Purchased Electric Commodity Account, or its successor or another account designated by the Commission on a current basis, for recovery in retail rates subject to subsequent Commission review.

ARTICLE IX REPRESENTATIONS AND WARRANTIES

Section 9.01. *Representations and Warranties.*

- (a) Each person executing this Agreement for the respective Parties expressly represents and warrants that he or she has authority to bind the Party on whose behalf he or she has executed this Agreement.
- (b) Each Party represents and warrants that it has the full power and authority to execute and deliver this Agreement and to perform its terms, that execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate or other action by such Party, and that this Agreement constitutes such Party's legal, valid and binding obligation, enforceable against such Party in accordance with its terms.
- (c) DWR represents and warrants that all necessary and appropriate notices, inducements, undertakings, approvals, and consents have been obtained from each Supplier to the Contract allocated to Utility in order for Utility to undertake its duties set forth in this Agreement in a timely and appropriate fashion.

ARTICLE X LIMITATIONS ON LIABILITY

Section 10.01. *Consequential Damages.* In no event will either Party be liable to the other Party for any indirect, special, exemplary, incidental, punitive, or consequential damages under any theory. Nothing in this Section 10.01 shall limit either Party's rights as provided in Article VII above.

Section 10.02. *Limited Obligations of DWR.* Any amounts payable by DWR under this Agreement shall be payable solely from moneys on deposit in the Department of Water Resources Electric Power Fund established pursuant to Section 80200 of the California Water Code (the "Fund").

Section 10.03. *Sources of Payment; No Debt of State.* DWR's obligation to make payments hereunder shall be limited solely to the Fund and shall be payable as an operating expense of the Fund solely from Power Charges subject and subordinate to each Priority Long Term Power Contract in accordance with the priorities and limitations established with respect to the Fund's operating expenses in any indenture providing for the issuance of Bonds and in the Rate Agreement and in the Priority Long Term Power Contracts. Any liability of DWR arising in connection with this Agreement or any claim based thereon or with respect thereto, including, but not limited to, any payment arising as the result of any breach or Event of Default under this Agreement, and any other payment obligation or liability of or judgment against DWR hereunder, shall be satisfied solely from the Fund. NEITHER THE FULL FAITH AND CREDIT NOR THE TAXING POWER OF THE STATE OF CALIFORNIA ARE OR MAY BE PLEDGED FOR ANY PAYMENT UNDER THIS AGREEMENT. Revenues and assets of the State Water Resources Development System, and Bond Charges under the Rate Agreement, shall not be liable for or available to make any payments or satisfy any obligation arising under this Agreement. If moneys on deposit in the Fund are insufficient to pay all amounts payable by DWR under this Agreement, or if DWR has reason to believe such funds may become insufficient to pay all amounts payable by DWR under this Agreement, DWR shall diligently pursue an increase to its revenue requirements as permitted under the Act from the appropriate Governmental Authority as soon as practicable. To the extent DWR's obligations are "administrative costs," they will require annual appropriation by the legislature.

Section 10.04. *Cap on Liability.* In no event will Utility be liable to DWR for damages under this Agreement, including indemnification obligations, whether in contract, warranty, tort (including negligence), strict liability or otherwise (referred to as "Damages" for purposes of this Section), in an amount in excess of: 1) on an annual calendar year basis, \$5 million plus ten percent of Damages in excess of \$5 million and 2) for the entire term of this Agreement, \$50 million in total payments of Damages to DWR. For example, if Damages for an event are \$100 million, Utility's total liability for this event would be \$14.5 million (\$5 million plus 10% of \$95 million) and that would be the full extent of Utility's liability for such Damages. All Damages associated with an event will apply only to the annual limit in the first year in which Damages for that event were assessed. For example, if Damages for an event were paid as follows: \$15 million in year 1 and \$10 million in year 2, the Utility would pay DWR \$7 million (\$5 million plus 10% of \$10 million for year 1 and 10% of \$10 million for year 2). In this example, the \$1 million paid to DWR in year 2 (10% of \$10 million) does not count against the year 2 \$5 million calendar year threshold. DWR hereby releases Utility from any liability for Damages in excess of the limitations on liability set forth in this Section 10.04, provided however, that this limitation on Utility liability shall not apply to the extent the liability is a result of Utility's gross negligence or willful misconduct.

ARTICLE XI CONFIDENTIALITY

Section 11.01. *Proprietary Information.*

- (a) Nothing in this Agreement shall affect Utility's obligations to observe any Applicable Law prohibiting the disclosure of Confidential Information regarding its customers.
- (b) Nothing in this Agreement, and in particular nothing in Sections 11.01(e)(x) through 11.01(e)(z) of this Agreement, shall affect the rights of the Commission to obtain from Utility, pursuant to Applicable Law, information requested by the Commission, including Confidential Information provided by DWR to Utility. Applicable Law, and not this Agreement, will govern what information the Commission may disclose to third parties, subject to any confidentiality agreement between DWR and the Commission.
- (c) The Parties acknowledge that each Party may acquire information and material that is the other Party's confidential, proprietary or trade secret information. As used herein, "Confidential Information" means any and all technical, commercial, financial and customer information disclosed by one Party to the other (or obtained from one Party's inspection of the other Party's records or documents), including any patents, patent applications, copyrights, trade secrets and proprietary information, techniques, sketches, drawings, maps, reports, specifications, designs, records, data, models, inventions, know-how, processes, apparatus, equipment, algorithms, software programs, software source documents, object code, source code, and information related to the current, future and proposed products and services of each of the Parties, and includes, without limitation, the Parties' respective information concerning research, experimental work, development, design details and specifications, engineering, financial information, procurement requirements, purchasing, manufacturing, business forecasts, sales and merchandising, and marketing plans and information. In all cases, Confidential Information includes proprietary or confidential information of any third party disclosing such information to either Party in the course of such third party's business or relationship with such Party. Utility's Confidential Information also includes any and all lists of customers, and any and all information about customers, both individually and aggregated, including but not limited to customers' names, street addresses of customer residences and/or facilities, email addresses, identification numbers, Utility account numbers and passwords, payment histories, energy usage, rate schedule history, allocation of energy uses among customer residences and/or facilities, and usage of DWR Power. All Confidential Information

disclosed by the disclosing Party ("Discloser") will be considered Confidential Information by the receiving Party ("Recipient") if identified as confidential and received from Discloser.

- (d) Each Party agrees to take all steps reasonably necessary to hold in trust and confidence the other Party's Confidential Information. Without limiting the generality of the immediately preceding sentence, each Party agrees (i) to hold the other Party's Confidential Information in strict confidence, not to disclose it to third parties or to use it in any way, commercially or otherwise, other than as permitted under this Agreement; and (ii) to limit the disclosure of the Confidential Information to those of its employees, agents or directly related subcontractors with a need to know who have been advised of the confidential nature thereof and who have acknowledged their express obligation to maintain such confidentiality. DWR shall not disclose Confidential Information to employees, agents or subcontractors that are in any respect responsible for power marketing or trading activities associated with the State Water Resources Development System.
- (e) The foregoing two paragraphs will not apply to any item of Confidential Information if: (i) it has been published or is otherwise readily available to the public other than by a breach of this Agreement; (ii) it has been rightfully received by Recipient from a third party without breach of confidentiality obligations of such third party and outside the context of the provision of services under this Agreement; (iii) it has been independently developed by Recipient personnel having no access to the Confidential Information; (iv) it was known to Recipient prior to its first receipt from Discloser, or (v) it has been summarized, processed and incorporated for incorporation into reports, discussions, statements or any other further work product. In addition, Recipient may disclose Confidential Information if and to the extent required by law or a Governmental Authority, provided that (x) Recipient shall give Discloser a reasonable opportunity to review and object to the disclosure of such Confidential Information, (y) Discloser may seek a protective order or confidential treatment of such Confidential Information, and (z) Recipient shall make commercially reasonable efforts to cooperate with Discloser in seeking such protective order or confidential treatment. Discloser shall pay Recipient its reasonable costs of cooperating.

Section 11.02. *No License.* Nothing contained in this Agreement shall be construed as granting to a Party a license, either express or implied, under any patent, copyright, trademark, service mark, trade dress or other intellectual property right, or to any Confidential Information now or hereafter owned, obtained, controlled by, or which is or may be licensable by, the other Party.

Section 11.03. *Survival of Provisions.* The provisions of this Article XI shall survive the termination of this Agreement.

ARTICLE XII RECORDS AND AUDIT RIGHTS

Section 12.01. *Records.* Utility shall maintain accurate records and accounts relating to the Contracts in sufficient detail to permit DWR to audit and monitor the functions to be performed by Utility on behalf of DWR, as its limited agent, under this Agreement. In addition, Utility shall maintain accurate records and accounts relating to DWR Revenues to be remitted by Utility to DWR, consistent with the Settlement Principles for Remittances and Surplus Revenues set forth in Exhibit C hereto. Utility shall provide to DWR and its Assign(s) access to such records. Access shall be afforded without charge, upon reasonable request made pursuant to Section 12.02. Access shall be afforded only during Business Hours and in such a manner so as not to interfere unreasonably with Utility's normal operations. Utility shall not treat DWR Revenues as income or assets of Utility or any affiliate for any tax, financial reporting or regulatory purposes, and the financial books or records of Utility and affiliates shall be maintained in a manner consistent with the absolute ownership of DWR Revenues by

Section 12.02. *Audit Rights.*

- (a) Upon 30 calendar days' prior written notice, DWR may request an audit, conducted by DWR or its agents (at DWR's expense), of Utility's records and procedures, which shall be limited to records and procedures containing information bearing upon Utility's performance of its obligations under this Agreement. The audit shall be conducted during Business Hours without interference with Utility's normal operations, and in compliance with Utility's security procedures.
- (b) As provided in the Act, the State of California Bureau of State Audits (the "Bureau") shall conduct a financial and performance audit of DWR's implementation of Division 27 (commencing with Section 80000) of the California Water Code, and the Bureau shall issue a final report on or before March 31, 2003. In addition, as provided in Section 8546.7 of the California Government Code, Utility agrees that, pursuant to this Section 12.02, DWR or the State of California Department of General Services, the Bureau, or their designated representative ("DWR's Agent") shall have the right to review and to copy (at DWR's expense) any non-confidential records and supporting documentation pertaining to the performance of this Agreement and to conduct an on-site review of any Confidential Information pursuant to Section 12.03 hereof. Utility agrees to maintain such records for such possible audit for three years after final Remittance to DWR. Utility agrees to allow such auditor(s) access to such records during Business Hours and to allow interviews of any employees who might reasonably have information related to such records. Further, Utility agrees to include a similar right for DWR or DWR's Agent to audit records and interview staff in any contract between Utility and a subcontractor directly related to performance of this Agreement.

Section 12.03. *Confidentiality.* Materials reviewed by either Party or its agents in the course of an audit may contain Confidential Information subject to Article XI above. The use of all materials provided to DWR or Utility or their agents, as the case may be pursuant to this Article XII, shall comply with the provisions in Article XI and shall be limited to use in conjunction with the conduct of the audit and preparation of a report for appropriate distribution of the results of the audit consistent with Applicable Law.

Section 12.04. *Annual Certifications.* At least annually, and in no event later than the tenth Business Day after the end of the calendar year, Utility shall deliver to DWR a certificate of an authorized representative certifying that to the best of such representative's knowledge, after a review of Utility performance under this Agreement, Utility has fulfilled its obligations under this Agreement in all material respects and is in compliance herewith in all material respects.

Section 12.05. *Additional Applicable Laws.* Each Party shall make an effort to promptly notify the other Party in writing to the extent such Party becomes aware of any new Applicable Laws or changes (or proposed changes) in Applicable Tariffs hereafter enacted, adopted or promulgated that may have a material adverse effect on either Party's ability to perform its duties under this Agreement. A Party's failure to so notify the other Party pursuant to this Section 12.05 will not constitute a material breach of this Agreement, and will not give rise to any right to terminate this Agreement or cause either Party to incur any liability to the other Party or any third party.

Section 12.06. *Other Information.* Upon the reasonable request of DWR or its Assign(s), Utility shall provide to DWR or its Assign(s) any public financial information in respect of Utility applicable to services provided by Utility under this Agreement, to the extent such information is reasonably available to Utility, which (i) is reasonably necessary and permitted by Applicable Law to monitor the performance by Utility hereunder, or (ii) otherwise relates to the exercise of DWR's rights or the

discharge of DWR's duties under this Agreement or any Applicable Law. In particular, but without limiting the foregoing, Utility shall provide to DWR any such information that is necessary or useful to calculate DWR's revenue requirements (as described in Sections 80110 and 80134 of the California Water Code).

Section 12.07. *Data and Information Retention.* All data and information associated with the provision and receipt of services pursuant to this Agreement shall be maintained for the greater of (a) the retention time required by Applicable Law or Applicable Tariffs for maintaining such information, or (b) three (3) years.

ARTICLE XIII DISPUTE RESOLUTION

Section 13.01. *Dispute Resolution.* Should any dispute arise between the Parties or should any dispute between the Parties arise from the exercise of either Party's audit rights contained in Section 12.02 hereof, the Parties shall remit any undisputed amounts and agree to enter into good faith negotiations as soon as practicable to resolve such disputes within (10) Business Days so as to resolve such disputes, as appropriate, within the timeframes provided under this Agreement, or as soon as possible thereafter. For any disputed Remittances, if such resolution cannot be made before the remittance date, Utility shall remit the undisputed portion to DWR. In addition, the disputed portion of the Remittances shall be deposited into an escrow account held by a qualified, independent escrow holder. Upon resolution of such disputes, the Party that escrowed the disputed amount shall reimburse the other Party from the escrow account as necessary.

Section 13.02. *ISO Settlements Disputes.* Utility shall review, validate and verify all ISO charges/credits contained on all ISO settlement statements, including any charges/credits resulting from functions related to the Contracts to be performed by Utility as provided in this Agreement. Utility shall inform DWR of any discrepancies and shall dispute any such discrepancies with the ISO in accordance with the ISO's tariff and protocols. Except as provided in Section 13.03, if any ISO charge type settlement amount appearing on a Preliminary or Final Settlement Statement (as defined in the ISO tariff) resulting or relating to the Utility's performance of functions related to the Contracts under this Agreement is in dispute, it shall be the responsibility of Utility, on behalf of DWR, as its limited agent, to seek resolution of said dispute through the ISO dispute resolution process as provided in the ISO's tariff.

For disputes affecting Utility's Remittances to DWR, including disputes on ISO charges to non-DWR parties that would affect Remittances to DWR, Utility shall provide to DWR: a) notification of submission of the dispute through the ISO dispute resolution process, identifying, among other items, the dispute type, quantity, price and allocation; b) a copy of the submitted dispute and all supporting data; and c) a copy of all ensuing documentation resulting from the ongoing dispute resolution process. Utility shall track and validate all disputed ISO charges involving any financial responsibility of DWR.

Section 13.03. *Supplier Invoice Disputes.* DWR shall continue to be responsible for all dispute resolution relating to Supplier invoices. In addition, except as specifically provided in Exhibit E of this Agreement, all other contract administration functions shall remain DWR's responsibility.

Section 13.04. *Good-Faith Negotiations.* Should any dispute arise between the Parties relating to this Agreement, the Parties shall undertake good-faith negotiations to resolve such dispute. If the Parties are unable to resolve such dispute through good-faith negotiations, either Party may submit a detailed written summary of the dispute to the other Party. Upon such written presentation, each Party shall designate an executive with authority to resolve the matter in dispute. If the Parties are unable to resolve such dispute within 30 days from the date that a detailed summary of such dispute is presented in writing to the other Party, and the dispute relates solely to Utility's conduct, performance, acts

and/or omissions (and not to DWR's conduct performance, acts and/or omissions), then DWR may, at its sole discretion, present the dispute to the Commission for resolution, in accordance with Applicable Law. All other disputes shall be brought in a court of competent jurisdiction or a forum mutually acceptable to the Parties in accordance with Applicable Law. Nothing herein shall preclude either Party from challenging the decision or action which such Party deems may adversely affect its interests in any appropriate forum of the Party's choosing.

Section 13.05. *Costs.* Each Party shall bear its own respective costs and attorney fees in connection with respect to any dispute resolution process undertaken by it pursuant to this Article. Provided, however, DWR shall reimburse Utility all reasonably incurred costs, including, but not limited to, in-house and retained attorneys, consultants, witnesses, and arbitration costs, arising from or pertaining to all disputes relating to ISO charges/credits contained on all ISO settlement statements resulting from the operational, dispatch and administrative functions related to the Contracts performed by Utility on behalf of DWR, as its limited agent, pursuant to the standards set forth in Section 2.02 herein and consistent with the provisions of the ISO tariff, as may be amended from time to time, including disputes on ISO charges to non-DWR parties that would affect Remittances to DWR. These costs shall be recorded and invoiced in the manner set forth in Section 8.01 hereof.

ARTICLE XIV MISCELLANEOUS

Section 14.01. *Assignment*

- (a) Except as provided in paragraphs (b) (c), (d) and (e) below, neither Party shall assign or otherwise dispose of this Agreement, its right, title or interest herein or any part hereof to any entity, without the prior written consent of the other Party. No assignment of this Agreement shall relieve the assigning Party of any of its obligations under this Agreement until such obligations have been assumed by the assignee. When duly assigned in accordance with this Section 14.01(a) and when accepted by the assignee, this Agreement shall be binding upon and shall inure to the benefit of the assignee. Any assignment in violation of this Section 14.01 (a) shall be void.
- (b) Utility acknowledges and agrees that DWR may assign or pledge its rights to receive performance hereunder to a trustee or another party ("Assign(s)") in order to secure DWR's obligations under its bonds (as that term is defined in the Act), and any such Assign shall be a third party beneficiary of this Agreement; provided, however, that this authority to assign or pledge rights to receive performance hereunder shall in no event extend to any person or entity that sells power or other goods or services to DWR.
- (c) Any person (i) into which Utility may be merged or consolidated, (ii) which may result from any merger or consolidation to which Utility shall be a party or (iii) which may succeed to the properties and assets of Utility substantially as a whole, which person in any of the foregoing cases executes an agreement of assumption to perform every obligation of Utility hereunder, shall be the successor to Utility under this Agreement without further act on the part of any of the Parties to this Agreement; provided, however, that Utility shall have delivered to DWR and its Assign(s) an opinion of counsel reasonably acceptable to DWR stating that such consolidation, merger or succession and such agreement of assumption complies with this Section 13.01(c) and that all of Utility's obligations hereunder have been validly assumed and are binding on any such successor or assign.
- (d) Notwithstanding anything to the contrary herein, DWR's rights and obligations hereunder shall be transferred, without any action or consent of either Party hereto, to any entity created by the State legislature which is required under Applicable Law to assume the rights and obligations of DWR under Division 27 of the California Water Code.

- (e) Notwithstanding anything to the contrary herein, Utility's rights and obligations under this Agreement may be assigned to the reorganized debtor under a plan of reorganization approved by the Bankruptcy Court for Utility without any action or consent of either Party hereto.

Section 14.02. *Force Majeure.* Neither Party shall be liable for any delay or failure in performance of any part of this Agreement (including the obligation to remit money at the times specified herein) from any cause beyond its reasonable control, including but not limited to, unusually severe weather, flood, fire, lightning, epidemic, quarantine restriction, war, sabotage, act of a public enemy, earthquake, insurrection, riot, civil disturbance, strike, restraint by court order or Government Authority, or any combination of these causes, which by the exercise of due diligence and foresight such Party could not reasonably have been expected to avoid and which by the exercise of due diligence is unable to overcome.

Section 14.03. *Severability.* In the event that any one or more of the provisions of this Agreement shall for any reason be held to be unenforceable in any respect under applicable law, such unenforceability shall not affect any other provision of this Agreement, but this Agreement shall be construed as if such unenforceable provision or provisions had never been contained herein.

Section 14.04. *Survival of Payment Obligations.* Upon termination of this Agreement, each Party shall remain liable to the other Party for all amounts owing under this Agreement. Utility shall continue to collect and remit, pursuant to the terms of the Servicing Arrangement and the principles provided in the Settlement Principles for Remittances and Surplus Revenues provided in Exhibit C hereto and any DWR Charges billed to customers or any DWR Surplus Energy Sales Revenues attributable to sales entered into before the effective date of termination of the Servicing Arrangement.

Section 14.05. *Third-Party Beneficiaries.* The provisions of this Agreement are exclusively for the benefit of the Parties and any permitted assignee of either Party and there are no third party beneficiaries under this Agreement.

Section 14.06. *Governing Law.* This Agreement shall be interpreted, governed and construed under the laws of the State of California without regard to choice of law provisions.

Section 14.07. *Multiple Counterparts.* This Agreement may be executed in multiple counterparts, each of which shall be an original.

Section 14.08. *Section Headings.* Section and paragraph headings appearing in this Agreement are inserted for convenience only and shall not be construed as interpretations of text.

Section 14.09. *Amendments.* No amendment, modification, or supplement to this Agreement shall be effective unless it is in writing and signed by the authorized representatives of both Parties and approved as required, and by reference incorporates this Agreement and identifies the specific portions that are amended, modified, or supplemented or indicates that the material is new. No oral understanding or agreement not incorporated in this Agreement is binding on either of the Parties.

Section 14.10. *Amendment Upon Changed Circumstances.* The Parties acknowledge that compliance with any Commission decision, legislative action or other governmental action (whether issued before or after the Effective Date of this Agreement) affecting the operation of this Agreement, including but not limited to (i) dissolution of the ISO, (ii) changes in the ISO market structure, (iii) a decision regarding direct access currently pending before the Commission, (iv) the establishment of other Governmental Programs, or (v) a modification to the Contract Allocation Agreement may require that amendment(s) be made to this Agreement. The Parties therefore agree that if either Party reasonably determines that such a decision or action would materially affect the services to be provided hereunder or the reasonable costs thereof, then upon the issuance of such decision or the approval of such action (unless and until it is stayed), the Parties will negotiate the amendment(s) to this

Agreement that is (or are) appropriate in order to effectuate the required changes in services to be provided or the reimbursement thereof. If the Parties are unable to reach agreement on such amendments within 60 days after the issuance of such decision or approval of such action, either Party may, in the exercise of its sole discretion, submit the disagreement to the Commission for proposed resolution. Nothing herein shall preclude either Party from challenging the decision or action which such Party deems may adversely affect its interests in any appropriate forum of the Party's choosing.

The Parties agree that, if the rating agencies request changes to this Agreement which the Parties reasonably determine are necessary and appropriate, the Parties will negotiate in good faith, but will be under no obligation to reach agreement or to ask the Commission to amend this Agreement to accommodate the rating agency requests and will cooperate in obtaining any required approvals of the Commission or other entities for such amendments.

Section 14.11 *Indemnification.*

- (a) *Indemnification of DWR.* Utility (the "Indemnitor") shall at all times protect, indemnify, defend and hold harmless DWR, and its elected officials, appointed officers, employees, representatives, agents and contractors (each, an "Indemnified Party" or an "Indemnitee") from and against (and pay the full amount of) any and all claims (whether in tort, contract or otherwise), demands, expenses (including, without limitation, in-house and retained attorneys' fees) and liabilities for losses, damage, injury and liability of every kind and nature and however caused, and taxes (of any kind and by whomsoever imposed), to third parties arising from or in connection with (or alleged to arise from in connection with): (1) any failure by Utility to perform its material obligations under this Agreement; (2) any material representation or warranty made by Utility shall prove to be false, misleading or incorrect in any material respect as of the date made; (3) the gross negligence or willful misconduct of Utility or any of its officers, directors, employees, agents, representatives, subcontractors or assignees in connection with this Agreement; and (4) any violation of or failure by Utility or Indemnitor to comply with any Applicable Commission Orders or Applicable Law; provided, however, that the foregoing indemnifications and protections shall not extend to any losses arising from gross negligence or willful misconduct of any Indemnified Party.
- (b) *Obligation of Utility.* Consistent with the Contract Allocation Order, Utility shall not, in acting as limited agent of DWR hereunder be required to perform any obligations of any Supplier under any Allocated Contract or to make any payments on behalf of such Supplier or as the result of the failure of such Supplier to perform under any Allocated Contract.
- (c) *Indemnification of Utility.* To the extent permitted by law, DWR ("Indemnitor") shall at all times protect, indemnify, defend and hold harmless Utility, and its officers, employees, representatives, agents and contractors (each, an "Indemnified Party" or "Indemnitee"), from and against (and pay the full amount of) any and all claims (whether in tort, contract or otherwise), demands, expenses (including, without limitation, in-house and retained attorneys' fees) and liabilities for losses, damage, injury and liability of every kind and nature and however caused, and taxes (of any kind and by whomsoever imposed), to third parties arising from or in connection with (or alleged to arise from on in connection with): (1) any failure by DWR to perform its material obligations under this Agreement or any Allocated Contract and, prior to novation, any Interim Contract; (2) any material representation or warranty made by DWR shall prove to be false, misleading or incorrect in any material respect as of the date made; (3) the gross negligence or willful misconduct of the DWR or any of its officers, directors or employees, agents, representatives, subcontractors or assignees in connection with this Agreement; (4) any action claiming Utility failed to perform any Supplier's obligations under a Contract; and (5) any violation of or failure by DWR or Indemnitor to comply with any Applicable Law; and provided, however, that the foregoing

indemnifications and protections shall not extend to any losses arising from the gross negligence or willful misconduct of any Indemnified Party.

- (d) *Indemnification Procedures.* Indemnatee shall promptly give notice to Indemnitor of any claim or action to which it seeks indemnification from Indemnitor. Indemnitor shall defend any such claim or action brought against it, and may also defend such claim or action on behalf of the Indemnatee (with counsel reasonably satisfactory to Indemnitor) unless there is any actual or potential conflict between Indemnitor and Indemnatee with respect to such claim or action. If there is any actual or potential conflict between Indemnitor and Indemnatee with respect to such claim or action, Indemnatee shall have the opportunity to assume (at Indemnitor's expense) defense of any claim or action brought against Indemnatee by a third party; however, failure by Indemnatee to request defense of such claim or action by the Indemnitor shall not affect Indemnatee's right to indemnity under this Section 14.11. In any action or claim involving Indemnatee, Indemnitor shall not settle or compromise any claim without the prior written consent of Indemnatee.

Section 14.12. *Notices and Demands.* (a) Except as otherwise provided under this Agreement, all notices, demands, or requests pertaining to this Agreement shall be in writing and shall be deemed to have been given (i) on the date delivered in person, (ii) on the date when sent by facsimile (with receipt confirmed by telephone by the intended recipient or his or her authorized representative) or electronic transmission (with receipt confirmed telephonically or electronically by the intended recipient or his or her authorized representative) or by special messenger, or (iii) 72 hours following delivery to a United States post office when sent by certified or registered United States mail postage prepaid, and addressed as set forth below:

Utility: Pacific Gas and Electric Company
245 Market Street, Room 1267
San Francisco, CA 94105-1814

Attn: Roy Kuga
Lead Director of Gas and Electric Supply
Telephone: (415) 973-3806
Facsimile: (415) 973-0585
Email: rmk4@pge.com

DWR: State of California
The Resources Agency
Department of Water Resources
California Energy Resources Scheduling Division
3310 El Camino Avenue, Suite 120
Sacramento, California 95821

Attn: Peter S. Garriss
Deputy Director
Telephone: (916) 574-2733
Facsimile: (916) 574-0301
Email: pgarris@water.ca.gov

- (a) Each Party shall be entitled to specify as its proper address any other address in the United States, or specify any change to the above information, upon written notice to the other Party complying with this Section 14.12.
- (b) Each Party shall designate on Attachment A the person(s) to be contacted with respect to specific operational matters. Each Party shall be entitled to specify any change to such person(s) upon written notice to the other Party complying with this Section 14.12.

Section 14.13. *Approval.* This Agreement shall be effective upon the execution by both Parties and approval of such executed agreement by the Commission. Except as expressly provided otherwise herein, neither Party may commence performance hereunder until such date. Any delay in the commencement of performance hereunder as a consequence of waiting for such approval(s) shall not be a breach or default under this Agreement.

Section 14.14. *Government Code and Public Contract Code Inapplicable.* DWR has determined, pursuant to Section 80014(b) of the California Water Code, that application of certain provisions of the Government Code and Public Contract Code applicable to State contracts, including but not limited to advertising and competitive bidding requirements and prompt payment requirements, would be detrimental to accomplishing the purposes of Division 27 (commencing with Section 80000) of the California Water Code and that such provisions and requirements are therefore not applicable to or incorporated in this Agreement.

Section 14.15. *Annual Review.* The provisions of the Exhibits are subject to annual review by DWR and Utility to ensure their relevance and usefulness. In the event that the Parties mutually agree that certain provisions of the Exhibits should be amended or supplemented, an amendment to the Exhibit should be executed and Utility shall submit to the Commission for approval.

Section 14.16. *Other Operating Agreement.* It is DWR's intent to have a consistent operating agreement with all three investor-owned utilities (IOUs). Should DWR reach an operating agreement with another IOU relating to the subject matter of this Agreement, that in Utility's judgment is more favorable on the whole than this Agreement, Utility shall have the right to receive the same terms and conditions as such other IOU. This provision specifically does not allow Utility to select particular portions or provisions of such other IOU's operating agreement. In addition, if Utility elects to be subject to such other IOU's operating agreement's terms and conditions, Utility shall be subject to such other IOU's operating agreement with only such modifications agreed to by DWR as necessary to address operating differences between that other IOU and Utility. Utility shall exercise the foregoing right within 60 days following Commission approval of such other operating agreement.

IN WITNESS WHEREOF, the Parties have executed this Agreement on the date or dates indicated below, to be effective as of the Effective Date.

CALIFORNIA STATE DEPARTMENT OF WATER RESOURCES,
acting solely under the authority and powers granted by AB1X,
codified as Sections 80000 through 80270 of the Water Code, and not
under its powers and responsibilities with respect to the State Water
Resources Development System

PACIFIC GAS & ELECTRIC COMPANY, a California corporation

By:	/s/ VIJU PATEL	By:	/s/ ROY M. KUGA
Name:	Viju Patel	Name:	Roy M. Kuga
Title:	Executive Manager	Title:	Vice President, Gas & Electric Supply
Date:	11/12/04	Date:	11-12-04

Schedule 1

ALLOCATED CONTRACTS

Schedule 2

INTERIM CONTRACTS

Schedule 3

REPRESENTATIVES AND CONTACTS

DWR/PG&E EXHIBIT A
OPERATING PROTOCOLS

EXHIBIT A
OPERATING PROTOCOLS

Pursuant to Section 4.01 of this Agreement, on behalf of DWR as its limited agent, Utility shall perform the day-to-day scheduling and dispatch functions, including day-ahead, hour-ahead and real-time trading, scheduling of transactions with all involved parties, making surplus energy sales and obtaining relevant information for these functions such as transmission availability and others, with respect to the Allocated Contracts set forth in Schedule 1 to the Agreement, and, prior to novation, the Interim Contracts set forth in Schedule 2, all as more specifically provided below and in compliance with the provisions of each of the Contracts:

- I. *Resource Commitment and Dispatch.* Utility agrees to use good faith efforts to dispatch Allocated Contracts, and, prior to novation, Interim Contracts, based on the principle of "least cost dispatch" to retail customers, consistent with the Contract Allocation Order and other Applicable Commission Orders. Utility shall undertake these least cost dispatch functions both of the Contracts and its URG so as to minimize the cost of service to retail customers based on circumstances known or that reasonably could have been known by Utility at the time dispatch decisions are made. DWR shall have no role in enforcement or review of Utility least cost dispatch under this Agreement and all issues of Utility compliance with least cost dispatch shall be within the sole review of the Commission.
- A. *Annual, Quarterly and Weekly Load and Resource Assessment Studies.* Utility shall provide to DWR copies of its annual and quarterly load and resource assessment studies. Provided that Utility submits substantially the same information to the Commission, copies of the Commission submission will be simultaneously sent to DWR to satisfy requirements of this section. In addition, Utility will provide a weekly commitment and dispatch plan for informational purposes to DWR in the same form that such plan is used internally.
- B. *Scheduling Protocols.*
1. DWR is responsible for notifying the counter-party to each of the Allocated Contracts that scheduling under the Allocated Contracts will be performed by Utility before the first day that schedules are due to be submitted by Utility. DWR is responsible for notifying Utility of any changes to the Allocated Contracts that it has negotiated, including changes to the scheduling terms. DWR agrees to provide such notice as soon as possible following the negotiation of any changed provisions and in any case prior to the time that any changed provisions become effective.
- To the extent that any of the Interim Contracts are amended or modified by DWR or Utility, including changes to the scheduling terms, DWR and Utility agree to provide such notice to the other Party as soon as possible following the negotiation of any changed provisions and in any case prior to the time that any such changed provisions become effective.
2. Utility agrees to schedule Contracts in accordance with their terms and in accordance with the requirements of the Control Area operator or operators with whom the Contract must be scheduled to provide for power delivery.
- II. *ISO Ancillary Service (AS) Market.* Among the Contracts are resources that are or may be qualified to be bid into the ISO's Ancillary Services ("AS") market or that Utility may use in its self-provision of AS. Utility is authorized to develop protocols and procedures for the use of DWR resources for AS. Utility shall, upon DWR's request, provide to DWR such information concerning Utility's intended use of DWR resources for AS as DWR may reasonably request for planning and revenue requirement purposes.

III. *Surplus Energy Sales and Energy Exchanges*

- A. *Over-generation.* If the ISO announces an over-generation situation Utility will back down resources in accordance with the ISO tariff and Good Utility Practice. In order to reduce the need for physical curtailment in over-generation situations, DWR and Utility shall develop pay for curtailment protocols and procedures that will enable Utility to instruct a must-take resource not to deliver energy under specified conditions. The costs and charges associated with mitigation of an over-generation situation shall be allocated among the Parties on a pro-rata basis consistent with the surplus sales allocation principles set forth in Exhibit C.
- B. *Energy Exchange Arrangements.* Existing non-DWR/CERS exchanges and those that might be transacted post-2002, will be considered URG exchanges. The accounting of energy necessary to support energy exchanges is addressed in Exhibit C.
- C. *Surplus Energy Sales Arrangement.* Utility shall on a monthly basis prepare a sales plan addressing all surplus sales, including without limitation sales to manage over-generation, contemplated by the Utility for review by DWR. Such plan shall address sales of power from the combined portfolio of URG resources and Contracts, which will be administered by Utility on its own behalf and acting as DWR's limited agent. As specified in Section 2.02 of the Agreement, Utility shall pursue surplus sales in a fashion reasonably designed to serve the overall best interests of retail electric customers based on information known or could have been known by Utility at the time. Utility agrees to include sufficient details in the sales plans to allow DWR to satisfy its financial management and reporting requirements. To the extent there is surplus power uncommitted to a forward energy surplus sales transaction, Utility shall be required to bid such surplus energy in the day-ahead, hour-ahead or real-time market. Utility shall arrange for transmission service to accommodate surplus sales to the extent that transmission service is available and cost effective. The costs of transmission service, ISO charges and the costs of firm transmission rights associated with such surplus energy sales transactions shall be treated in accordance with the Settlement Principles for Remittances and Surplus Revenues attached hereto as Exhibit C.

- IV. *Outage Coordination and Determination of Resource Availability of Contracts.* Utility shall communicate with the Scheduling Coordinator of each Contract to coordinate, approve, document and report planned Contract outages. For those Contracts where resource availability affects capacity payments, Utility will use good faith efforts to verify supplier actual resource availability, and keep records of resource availability as reported by Supplier. In addition, Utility shall document all outages (forced and planned) and notices of outages of DWR contract resources and provide such documents to DWR within five (5) business days after the end of each calendar month. Interim Contracts Utility and DWR agree that the Attachments and data requirements associated with this Agreement will be updated as needed to incorporate the addition of new Interim Contracts entered into after the execution date of this Agreement.

DWR/PG&E EXHIBIT B
FUEL MANAGEMENT PROTOCOLS

EXHIBIT B
FUEL MANAGEMENT PROTOCOLS

Certain of the Contracts listed on Schedule 1 of this Agreement provide DWR the option of either (i) letting the Supplier provide the necessary natural gas for its generating units at an index-based price or agreed upon fixed price or (ii) DWR procuring the gas supply and causing such supply to be delivered to the Supplier under a tolling arrangement ("Fuel Option"). Certain of the Contracts with Fuel Option provide that DWR can decide on a monthly basis whether to procure the gas and others provide that the decision be made annually or semi-annually when DWR reviews the Supplier's proposed fuel plan.

The purpose of this Exhibit B is to describe the relationship which will exist between DWR and Utility and the specific responsibilities of each as they all relate to managing the natural gas provisions of the Contracts which include Fuel Options. Specifically, this Exhibit B will address responsibilities for the following activities: (i) determining types and lengths of gas contracts, (ii) nominating deliveries, (iii) contracting for gas transportation and storage, (iv) managing imbalances, (v) reviewing, authorizing and making payment of gas invoices and (vi) determining and implementing hedge strategies, as appropriate.

I. Operating Relationship Between DWR and Utility

While DWR will retain legal and financial responsibility for gas and related services, Utility shall, as a limited agent acting for DWR, perform the administrative and operational activities, as further specified below, required to ensure adequate gas is supplied to Suppliers' generating units, consistent with the tolling provisions included in the Contracts. The intent of this relationship is to provide Utility sufficient flexibility and authority to execute normal day-to-day activities associated with managing the fuel provisions of tolling Contracts and procurement of natural gas and related services, as a limited agent acting on behalf of DWR without direct involvement by DWR but in a manner consistent with Utility Gas Supply Plans which have been reviewed and approved by DWR and the Commission.

II. Fuel Activities

Consistent with the terms of the Contracts with Fuel Options, Utility shall have administrative and operational authority to act, as a limited agent, for fuel supply related activities, consistent with the following goals and guidelines whenever Utility has recommended, and DWR has reviewed and approved such recommendation that gas for a Contract with Fuel Option be caused to be supplied by Utility from a list of approved providers.

1. Utility shall use reasonable commercial efforts to secure delivery of gas in a reliable manner and consistent with gas requirements for producing scheduled energy.
2. Utility shall develop a portfolio of gas supply for the Contracts that contain Fuel Options and where Utility is to supply gas, acting as limited agent on behalf of DWR, consistent with the approved Utility Gas Supply Plans. Such portfolio should be diversified in terms of price mechanism, period of performance, and gas suppliers.
3. Utility shall develop a portfolio of supply which is reasonably priced relative to the market and in accordance with an approved Utility Gas Supply Plan.

III. Review of Supplier Fuel Plans

In accordance with the terms of each of the Contracts with Fuel Options, Utility, acting as a limited agent on behalf of DWR, shall review each fuel plan prepared and submitted by the Supplier, and forwarded to the Utility by DWR, and determine whether to recommend (i) approval of the Supplier Fuel Plan and authorization for the Supplier to provide gas to its generating unit(s), or (ii) procurement and management of gas supplies to the generating unit(s) by Utility. Utility, acting as a limited agent on behalf of DWR, shall advise DWR and the

Commission on a timely basis of its recommendation regarding responsibility for supplying natural gas. DWR shall, on a timely basis, review Utility's recommendation and either approve or identify requested changes. Once approved, Utility shall advise the Supplier in accordance with the time requirements included in the appropriate Contract with Fuel Option. In addition, for any Supplier Fuel Plans which have been implemented and are operative as of the Effective Date, and where DWR has previously elected to be responsible for gas supply, Utility may advise DWR that it would rather have Supplier provide the gas as of the Effective Date. DWR shall coordinate with Utility and Supplier to revise such Supplier Fuel Plans, to the extent possible, prior to the Effective Date.

IV. Fuel Procurement Strategies

Under the Contracts with Fuel Option, upon Utility's recommendation, and DWR's review and approval of such recommendation, Utility will be responsible for procuring the natural gas fuel from a list of approved gas providers. Utility shall, acting as the limited agent of DWR, have administrative and operational responsibility for determining its gas procurement strategies, including but not limited to (i) types of contracts, (ii) length of contracts, (iii) pricing terms, (iv) use of storage, (v) types of gas transportation, (vi) delivery point(s), (vii) whether and how to obtain gas price forecasts, (viii) if and what risk management tools are to be used, and (ix) how to maintain current market intelligence.

Utility shall consolidate these strategies and submit them to DWR and the Commission as a "Utility Gas Supply Plan" by April 17, 2003 and, thereafter on a semi-annual basis during the Term. Utility may also provide a copy of such Gas Supply Plan to DWR in advance of the filing with the Commission so as to be able to indicate DWR's approval of such plan. Utility shall indicate in its Advice Letter filing to the Commission whether DWR has approved such plan as appropriate. DWR shall also formally notify the Commission when it has approved such plan.

DWR and the Commission will review and approve the Utility Gas Supply Plans. In the event of conflicting guidance between the Commission and DWR regarding various aspects of the Gas Supply Plan they respectively approve or reject, where DWR only approves a subset of what the Commission approves, then Utility shall operate within the sphere of DWR's approval. If, however, the Commission explicitly rejects portions of the Gas Supply Plan that DWR would authorize, then Utility must operate within the limitations of the Commission's decision. After a reasonable period of time operating within the framework of the Gas Supply Plans and the Commission's and DWR's respective approval and/or rejection of various pieces of the Gas Supply Plan, the Parties agree to meet and confer to determine whether the approval process may need to be revised in some manner, and Utility shall submit to Commission any such proposed revisions. Once approved, Utility may act within such Utility Gas Supply Plan without further DWR involvement, except as provided below.

V. Gas Purchasing

Utility and DWR shall jointly determine a list of approved gas providers who can be used to supply gas under the Contracts with Fuel Options. Master agreements intended to cover normal day-to-day volumes will then be executed with such approved providers. While DWR will be the executing party under all DWR gas contracts, such agreements shall specifically authorize Utility to act for and on behalf of DWR, as a limited agent, in negotiating specific prices, quantities and delivery periods for specific purchases under such master agreements; provided however, on the earliest practicable date after the execution of this Agreement, DWR agrees to provide to Utility in writing and in advance of such negotiations any limits, including without limitation any terms, that may be required by DWR. If Utility determines it would be beneficial to enter into any DWR gas contract which exceeds 3 months or have a total value exceeding \$10 million, it shall negotiate such agreement(s) and submit them to DWR for advance approval and execution.

VI. Gas Transportation

Utility shall have responsibility for recommending to DWR which pipelines should transport gas if Utility, acting as limited agent on behalf of DWR is to supply gas under a Contract with Fuel Option. Following approval of or revision of Utility Gas Supply Plan, Utility shall negotiate firm and/or interruptible agreements with such pipelines, consistent with the Utility Gas Supply Plan and submit them to DWR for execution. While DWR will be the executing party, such agreements with pipelines shall specifically authorize Utility to act for and on behalf of DWR in nominating gas deliveries, making imbalance trades and managing gas volumes transported under such agreements provided, however, on the earliest practicable date after the execution of this Agreement, DWR agrees to provide to Utility in writing and in advance of such negotiations any limits, including without limitation any terms, that may be required by DWR.

VII. Gas Scheduling

If permitted under the Contracts, the Utility shall have full administrative and operational responsibility for scheduling gas deliveries, whether to a specific generating plant or to storage for all gas contracts entered into by DWR or by Utility on DWR's behalf pursuant to this Exhibit B. This function includes use of interstate and intrastate gas pipeline provider websites, confirming via telephone, and all other activities required to move gas from the designated delivery point, as determined by the Utility, to its destination, as determined by the Utility.

VIII. Storage Capacity, Injections and Withdrawals

Utility shall have responsibility for devising plans for gas storage, if Utility, acting as limited agent on behalf of DWR, is to supply gas under Contracts with Fuel Option from a list of approved providers. Following approval of the Utility Gas Supply Plans, Utility shall negotiate firm and/or interruptible agreements with such storage service providers and submit them to DWR for execution. While DWR will be the executing party with DWR remaining the principal under such contracts, such agreements with storage service providers shall specifically authorize Utility to act for and on behalf of DWR in nominating gas injections and withdrawals under such agreements; provided, however, on the earliest practicable date after the execution of this Agreement, DWR agrees to provide to Utility in writing and in advance of such negotiations any limits, including without limitation any terms, that may be required by DWR.

IX. Managing Gas Delivery/Usage Imbalances

For gas that it purchases and transports on behalf of DWR, Utility shall have full administrative and operational responsibility for monitoring and managing the daily status of gas usage vs. gas deliveries (i.e. gas imbalances). In addition, to the extent that gas transportation providers issue operational flow orders or require adjustments in scheduled gas deliveries due to system constraints, Utility, acting as limited agent on behalf of DWR, shall be responsible for compliance with such orders. Utility shall also be responsible for any penalties imposed by gas transportation providers for imbalances caused by Utility, due to its failure to exercise prudent gas management practices.

X. Invoice Review, Approval and Payment

For natural gas, pipeline transportation and storage services it purchases in accordance with this Exhibit B, Utility, acting as limited agent on behalf of DWR, shall have responsibility for receiving invoices from gas, transportation and storage suppliers, reviewing them for accuracy, approving/rejecting invoices for payment and forwarding to DWR for payment; provided, however, on the earliest practicable date after the execution of this Agreement, DWR agrees to cause Utility to be authorized to receive such information from Suppliers. Utility shall provide DWR sufficient documentation to verify payment of the invoices.

XI. Forecasting

Utility shall be responsible for all gas price, demand and supply forecasts which Utility believes are consistent with any accepted gas supply responsibilities.

XII. Risk Management

Utility shall develop and include in its Gas Supply Plans, plans for the hedging of DWR Fuel Supply costs. Final decisions relating to the use or non-use of financial tools such as futures, options and swaps to hedge future gas price exposure on any gas volumes not hedged by Utility under the Utility Gas Supply Plans shall be made and implemented by DWR. Any such contracts executed by DWR on a "portfolio basis" should be utility-specific.

XIII. Market Intelligence

Any and all efforts to obtain, analyze and utilize market intelligence for decision-making purposes shall be the responsibility of Utility.

XIV. Payment of Gas Costs

For natural gas, pipeline transportation, financial hedges and storage services that are purchased and provided by a Supplier under an approved Fuel Supply Plan, DWR shall pay such gas related costs as part of the invoice for commodity, product, or services submitted by the Supplier. For natural gas, pipeline transportation and storage services provided under DWR contracts and administered by Utility on behalf of DWR, DWR shall pay invoices after they have been reviewed and approved for payment by Utility.

XV. Allocation of Existing DWR Gas Contracts

DWR has entered into gas supply, transportation and storage contracts as provided in Attachment 1 to this Exhibit B that have expiration dates after the Effective Date of this Agreement. The administrative and operational control of the contracts listed on Attachment 1 to this Exhibit B will become the responsibility of Utility. This shall include (i) scheduling gas transportation, (ii) confirming gas deliveries, (iii) nominating gas withdrawals from and injections into storage, if applicable, (iv) and reviewing and approving invoices for payment. When approved, invoices shall be transmitted to DWR for payment within 10 days of receipt of invoice from the gas supplier, gas storage or gas transportation provider.

XVI. Pre-existing Financial Hedge Instruments

If DWR has entered into any financial hedge transactions that will remain operable after the Effective Date of this Agreement, DWR shall retain full administrative and operational control over such transactions.

DWR/PG&E EXHIBIT C

**SETTLEMENT PRINCIPLES
FOR REMITTANCES AND
SURPLUS REVENUES**

EXHIBIT C

SETTLEMENT PRINCIPLES FOR REMITTANCES AND SURPLUS REVENUES

This Exhibit C outlines the principles by which Utility will calculate revenues associated with surplus energy sales and DWR energy delivered to retail customers. This Exhibit C also addresses the information that Utility will provide to DWR to support DWR payment of Contract invoices, and invoices from natural gas supplier(s) for fuel provided to service DWR Contracts where tolling options have been implemented.

This Exhibit C works in conjunction with the applicable Servicing Arrangement with Utility for purposes of determining the remittance amounts by Utility, which serves as DWR's billing and collection agent.

In accordance with the Contract Allocation Order(1), this Exhibit C provides that:

(1) Contract Allocation Order is CPUC Decision (D.) 02-09-053.

- Revenues will be allocated for both surplus sales and retail customer deliveries
- Revenues will be allocated pro rata, based on dispatched quantities of energy
- The principle of balancing least cost economic dispatch while maintaining reliability is reinforced through these revenue allocation protocols.
- Surplus sales quantities will be calculated as the difference between Utility's Energy Delivery Obligations (EDO) and the combination of energy from URG and energy dispatched from the Contracts.

Where Utility's Energy Delivery Obligations is defined as: (1) Utility's retail load(2) which includes distribution losses, (2) all pump-back loads, (3) energy exchange transactions between Utility and counter parties, (4) wholesale obligations, existing as of January 1, 2003, and (5) transmission losses.

(2) PG&E retail load obligations per CPUC May 2002 Service Order (D.02-05-048) includes Western Area Power Administration (WAPA) load, although this load is not retail load.

The principles herein, together with the applicable methods and calculations contained in the Servicing Arrangement, form a substantive component of the accounting protocols required to implement the Contract Allocation Order. This Exhibit should also be read in conjunction with Exhibit F ("Data Requirements").

Exhibit F may periodically be modified to include all data that DWR will require to verify the remittances of revenues as remittance or implementation protocols change. Utility and DWR agree to modify Exhibit F to include or exclude information reasonably determined by DWR to allow DWR to verify Net DWR Retail Supply and the surplus remittances.

Utility Remittance to DWR

Utility shall remit to DWR an Energy Payment for the delivery of Contract energy to Utility retail customers (including the delivery or Contract energy to WAPA) and a separate payment for DWR's share of Surplus Energy Sales Revenues. The principles for the remittances to DWR of Surplus Energy Sales Revenue and Energy Payment are contained in Sections A and B of this Exhibit C, respectively. The details for determination of the remittances to DWR by Utility are contained in the Servicing Arrangement.

A. Utility Remittance to DWR of Revenue from Surplus Energy Sales

Surplus Energy and Revenues

Surplus energy exists when dispatched supply from Utility portfolio and DWR Contracts exceeds Utility's Energy Delivery Obligations. When such a condition exists, the revenues from the sale of surplus energy shall be shared between Utility and DWR. Surplus sale revenues can occur either through a forward market sale or a delivery of the excess energy into the ISO real time market. In addition to the sharing of surplus energy revenues, the quantity of any surplus energy shall likewise be shared between Utility and DWR, and used in the determination of the Hourly Percentage Factor described in Section I.(B).

Surplus energy sales revenues shall be placed by Utility into a separate account (Surplus Sales Fund) to be held in trust and shall be disbursed by Utility to DWR in accordance with the pro-rata allocation principles in Exhibit C and consistent with the provisions of Attachment J of the Servicing Arrangement. For surplus energy sales to third parties, Utility shall apply reasonable credit risk management criteria that is consistent with industry accepted credit standards.

Surplus Energy Quantity

The Surplus Energy quantity shall be determined by subtracting Utility's Energy Delivery Obligations from the sum of dispatched URG energy and dispatched DWR Supply. URG energy shall include dispatched energy from URG, new Utility contracts and Utility market purchases plus adjustments for Ancillary Services and ISO Instructed Energy as described under "Definitions and Adjustments." DWR Supply shall include dispatched energy from DWR must take and dispatchable contracts plus adjustments described below.

DWR Surplus Energy quantity shall be the product of Surplus Energy quantity multiplied by the DWR Surplus Energy Percentage. Utility Surplus Energy quantity shall be the remaining portion of Surplus Energy. Both Utility and DWR Surplus Energy quantities shall be applied to the respective Party's energy supply quantities for determination of the Hourly Percentage Factor described in Section (B).

Surplus Energy Sales Revenues

Surplus Energy Sales Revenues shall be shared between Utility and DWR in the same manner as Surplus Energy.

Forward Market Sale

DWR share of revenues from a forward market sale of surplus energy shall be the product of the net revenue multiplied by the DWR Surplus Energy Percentage. Utility share of these revenues shall be net revenue less DWR share of net revenues. Revenues from a forward market sale shall not be distributed to the Parties until after Utility receives the revenues from the sales and pays sale-related charges. Shared revenues from forward market sales shall be net of transmission costs and broker fees.

ISO Real Time Market Sales

Revenues from delivery of surplus energy to the ISO real time market shall be determined from the product of positive load or supply deviation multiplied by the ISO real time market price. These revenues will be netted against any ISO charges related to the load deviation, including a negative ISO price. Load deviation is determined by subtracting the Utility metered load from the Final Hour Ahead Load Schedule, however only positive quantities, where schedule exceeds meter, reflect surplus conditions for revenue sharing. Supply deviation is determined by subtracting the Final Hour Ahead

Supply Schedule (adjusted by real time instructions) from metered supply, however, only positive quantities, where meter exceeds the adjusted schedule, reflect surplus conditions for revenue sharing.

DWR share of revenues from delivery of surplus energy to ISO real time market shall be the product of the net revenues multiplied by the DWR Surplus Energy Percentage. Utility share of these net revenues shall be the net revenue less DWR share of net revenues. Revenues from delivery of surplus energy to the ISO real-time market shall not be distributed to the Parties until after the Utility received payment for final monthly invoice from the ISO for the month in which the surplus energy was delivered.

Over-generation Periods

During periods of over-generation condition as announced by the ISO, surplus sales may be made at very low, zero or even negative prices. In such conditions, the surplus sale revenue calculations as described above still hold. However it is recognized that the sales may result in little or no revenue. Sales could even be done at a cost to the seller. That seller could be Utility or the ISO selling in an "out-of-market" condition. During these conditions, ISO-related charges assigned to Utility for such sales (e.g.—ISO selling out-of-market) are included in the surplus sales revenue as a cost. During over-generation conditions there may be no market in which to sell surplus energy. In that event, or in expectation of that event, Utility shall declare that no valid market exists for surplus energy and shall begin curtailing must-take resources in accordance with Utility's procedures for mitigating over-generation conditions. Such mitigation measures shall be consistent with good utility practice, specifically hydroelectric facilities at spill or near-spill conditions and nuclear facilities scheduled by Utility are the last resources to be reduced in power output.

Over-generation for purposes of this Exhibit C is defined as the condition in which total supply exceeds total loads in the ISO control area.

Revenues or costs from delivery of surplus energy to the ISO real time market under an over-generation condition shall not be distributed to the Parties until after Utility receives payment for final monthly invoice from the ISO for the month in which the surplus energy was delivered.

Calculation of Surplus Energy Percentage

DWR Surplus Energy Percentage shall be equal to the pro rata share of DWR Supply to the sum of Utility Supply and DWR Supply, expressed as follows:

$$\text{DWR Surplus Energy Percentage} = \text{DWR Supply} / (\text{Utility Supply} + \text{DWR Supply})$$

Where:

DWR Supply is total energy dispatched from DWR Contracts with adjustments for transmission losses, Ancillary Services and ISO Instructed Energy transactions described below.

Utility Supply is total energy dispatched from URG, new Utility contracts and Utility market purchases with adjustments for transmission losses, existing wholesale obligations, WAPA load, Ancillary Services and ISO Instructed Energy, exchange transactions, all pumping loads, and ISO Uninstructed Energy as described below.

B. Definitions and Adjustments

Certain energy and capacity transactions, which may be conducted by Utility in its normal course of business, may affect the Utility and DWR Supply quantities used in pro rata calculations.

Exchanges are transactions where energy is delivered to a third party in one period and a similar, but not necessarily equal, amount of energy is returned by third party in a different period. For the purposes of pro rata share calculation, exchanges use and supplement energy from the Utility Supply.

Forward Sales are transactions where energy is sold in a forward market to balance supply with demand. In general, for the purposes of remittance determination, forward sales are made using energy from the joint Utility/DWR portfolio.

Ancillary Services are transactions where capacity from certain qualifying resources is sold to ISO for ancillary services rather than being used as energy to serve retail load. Resources from both Utility portfolio and DWR Contracts may qualify for use as ancillary services. Since the capacity used for ancillary services does not serve retail energy load, ancillary service capacity is not considered as a joint Utility/DWR portfolio transaction for the purpose of remittance determination. If Utility or DWR Contract resource capacity is used for ancillary services, the capacity quantity will not be included in the supply quantity of the owning party for the purpose of pro rata share calculations, and owning party will retain all the revenues from the ancillary services as well as all associated transaction costs and ISO charges.

ISO Instructed Energy is a transaction where certain qualifying resources are able to sell energy from unused capacity to the ISO in the real time market. The energy delivered from these resources is directed by the ISO in real time to balance supply and load imbalances on the grid. Either Utility portfolio or DWR Contracts may contain resources that have ability to provide instructed energy to ISO. Since instructed energy is resource specific and does not directly serve the retail load of any utility, instructed energy is not considered as a joint Utility/DWR portfolio transaction for the purpose of remittance determination. If Utility or DWR Contract resources are dispatched as instructed energy, the energy quantity will not be included in the supply quantity of the owning party for the purpose of pro rata share calculations, and owning party will retain all the revenues from the instructed energy as well as all associated transaction costs and ISO charges.

ISO Uninstructed Energy is a transaction where energy is delivered or received from the ISO grid in the real time based on the actual consumption of retail load and actual deliveries of supply resources.

Uninstructed Retail Load Deviations

Uninstructed Load Deviations are the difference between scheduled load and metered load. If retail load deviations are positive (schedule exceeds meter), it is considered that any excess supply (less any positive uninstructed supply deviation) was dispatched from the joint Utility/DWR portfolio in excess of quantity needed to serve retail load, and that the ISO credit for the excess supply should be shared pro rata as described above. If retail load deviations are negative (meter exceed schedule), to the extent deviations are not compensated by a positive uninstructed supply deviation, it is considered that Utility had to procure additional supply from ISO real time market. The negative load deviation quantity procured from ISO real time market is considered a Utility market purchase and the quantity will be included in Utility Supply for pro rata share calculation purposes.

Uninstructed Supply Deviations are the difference between scheduled supply and metered supply plus an ISO allocation for transmission losses. If Utility's net supply deviations(2) are positive (meter exceeds schedule), to the extent not needed to compensate a negative uninstructed retail load deviation, it is considered that excess supply was a Utility market sale and will not be included in Utility Supply for pro rate calculation purposes. If Utility's net supply deviations are negative (schedule exceeds meter), to the extent not balanced by a positive uninstructed retail load deviation, it is considered that Utility had to procure additional supply from the ISO real time market. The negative supply deviation quantity procured from the ISO real time market is considered a Utility market purchase and the quantity will be included in Utility Supply for pro rata share calculation purposes.

-
- (2) Net positive and negative deviations of all supply resources.

Transmission Losses

Transmission loss is defined as Energy that is lost due to the process of transmitting energy from supply source to load. Therefore, supply resources from DWR Contracts and Utility Supply have distinct and identifiable quantity of transmission losses. Utility and DWR Supply should be net of transmission losses because of energy that is delivered to retail customers (i.e. load) equals quantity of supply less losses.

C. Utility Remittance to DWR for Sales of DWR Energy to Utility Retail Customers—Energy Payment

Utility shall remit to DWR its Energy Payments according to the terms of each Utility's respective Servicing Arrangement.

The DWR Energy Payment is billed by each utility to customers in accordance with the terms of each applicable Utility Servicing Arrangement. The DWR Energy Payment is billed kWhs served by Net DWR Supply at the applicable CPUC approved DWR rate. Net DWR Supply is total DWR Supply less DWR share of surplus energy. The DWR Energy Payment is allocated based on the percentage of energy supplied by DWR to Utility, which is the "Hourly Percentage Factor" multiplied by the retail load of each customer. The Hourly Percentage Factor is determined by calculating the percentage of net energy supplied by DWR to Utility to serve retail load, as expressed below:

$$\text{Hourly Percentage Factor} = \text{Net DWR Supply} / (\text{Net Utility Supply} + \text{Net DWR Supply})$$

Where:

Net DWR Supply is DWR Supply quantity used for the determination of DWR Surplus Energy Percentage less DWR share of surplus energy quantity, which is determined by the product of surplus energy multiplied by DWR Surplus Energy Percentage.

Net Utility Supply is Utility Supply quantity used for the determination of DWR Surplus Energy Percentage less Utility share of surplus energy quantity, which is total surplus energy less the DWR share of surplus energy quantity.

In the Event of any conflict between the formulas and procedures in this Exhibit C and the formulas and procedures in Utility's Servicing Arrangement, those contained in Utility's Servicing Arrangement shall govern.

II. Bilateral Settlement

Under the Contract Allocation Order DWR remains financially obligated for the Contracts. DWR will continue to pay suppliers and this requires DWR to apply appropriate procedures and controls to ensure that payments are made accurately and in a timely manner. Information supporting Contract settlements will be provided by Utility, and additional information may also be required to address contract performance issues (such as availability and other items as discussed in Exhibit E) and to allow DWR to settle disputes in an appropriate manner.

DWR requires sufficient information to support payment requests so that it can meet the accountability requirements of the State Controller's Office and the State Auditor, and simultaneously comply with the applicable statutes concerning disbursement of public monies. The Utility shall reconcile schedules with suppliers invoice. DWR shall make the associated payments to suppliers after performing its verification, and Utility will provide the data as required in Exhibit F to allow it to perform these duties in a timely manner as set forth herein.

DWR shall continue to perform validation of settlement data and invoices and pay Contract costs directly to the suppliers upon validation of invoices.

III. Fuel Cost Verification and Settlement

Exhibit B provides a detailed discussion concerning Utility's responsibility for fuel management. DWR will continue to pay fuel suppliers and others involved in providing fuel management services for the delivery of fuel for those DWR Contracts where the Fuel Option has been elected. Consistent with the above, Utility will perform settlements activities to reconcile quantities and associated charges, and DWR will perform verification, audit and monitoring to support its disbursement of funds. Utility will comply with the requirements contained in Exhibit F to provide DWR with the necessary information to apply appropriate procedures and controls to ensure that fuel payments and payments for fuel management services are made accurately and in a timely manner and to allow DWR to settle disputes in an appropriate manner.

DWR/PG&E EXHIBIT D

ISO SCHEDULING COORDINATOR CHARGES

EXHIBIT D
ISO SCHEDULING COORDINATOR CHARGES

The financial obligation for ISO charges incurred as of the Effective Date will be allocated to the Utility, unless otherwise extended under the existing and any future Applicable Commission Orders. Unless specifically provided in Exhibit C hereto, all ISO charges incurred after the Effective Date attributable to load and resources shall be the responsibility of Utility.

Utility agrees that any refunds, reruns or credits through the ISO attributable to costs incurred by DWR for trade dates beginning Hour Ending 2200, January 17, 2001 up to the Effective Date, which are separate from ISO charges subject to Commission Decision No. 02-05-048, shall belong to DWR and Utility shall take all necessary action to remit such refunds or credits to DWR within reasonable time. In addition, DWR shall be responsible for any ISO charges incurred during this period pursuant to the existing letter agreement between the Parties. Utility shall invoice DWR for such ISO charges within a reasonable period of time and DWR shall pay Utility for such ISO charges within 10 days of receipt of such invoice. Without making any assurances as to Commission action, DWR agrees to take appropriate action to ensure that such refunds or credits are applied consistent with DWR's Revenue Requirement cost allocation method for the same trade dates.

DWR agrees that any refunds, reruns, or credits through the ISO attributable to ISO charges invoiced to DWR under the November 7, 2001 order of the Federal Energy Regulatory Commission and subsequent orders but which are further subject to Commission Decision No.02-05-048, which directs Utility to directly reimburse DWR for such ISO charges incurred starting Hour Ending 2200, January 17, 2001 up to the Effective Date, shall belong to Utility and DWR shall take all necessary action to remit such refunds or credits directly to Utility within reasonable time.

DWR/PG&E EXHIBIT E

**CONTRACT MANAGEMENT AND
ADMINISTRATION PROTOCOLS**

EXHIBIT E
CONTRACT MANAGEMENT AND ADMINISTRATION PROTOCOLS

DWR will retain all contract management, administration and monitoring responsibilities for the Contracts, including due diligence, performance testing, contract performance assessment, formal correspondence and notifications with Suppliers, exercise of contract options, contract interpretation and dispute resolution, and financial reporting. In the event Utility and DWR agree in the future to transition the Due Diligence and Performance Test Monitoring functions set forth in this Exhibit E from DWR to the Utility, the Parties will first develop a mutually acceptable plan of performance, a transition schedule, and a transition plan for transfer of such functions from DWR to the Utility for review and approval by the Commission.. Upon agreement of the Parties to an acceptable plan and completion of the transition period, the agreed upon functions will transfer from DWR to the Utility ("the Transition Date").

I. Due-Diligence

The Due Diligence function assesses the progress of permitting, construction and performance capability of new generating facilities under to the Contracts. Due Diligence includes (i) monitoring activities associated with the development, construction, and performance of new generating facilities; (ii) identification and tracking of key projects milestones including permitting, equipment procurement, construction, commissioning, and performance testing; (iii) coordination with permitting agencies and the Suppliers, review of project documents, physical inspections, and witnessing of acceptance tests, (iv) verification that the new facilities can perform in a manner that is consistent with the obligations under the appropriate Contract and (v) review and approval of commercial operation dates and documentation.

II. Performance Test Monitoring

A. Annual Performance Tests

Annual Performance Tests verify ongoing compliance with the Contracts and establish plants capacities and efficiencies that are used to calculate contract payments, either for capacity or energy. Annual Performance Test responsibilities generally consist of (i) verification of testing procedures, (ii) witness of performance tests, (iii) review of test results and test reports for compliance with Contract terms and conditions, and (iv) identification of contract non-compliance for dispute resolution with the Supplier. Prior to the Transition Date, the Utility will cooperate and assist DWR with scheduling of upcoming Annual Performance Tests, and the Utility may have its staff witness such testing.

B. Scheduled Performance Tests

Prior to the Transition Date, on occasion, DWR may request that Utility schedule a peaking or dispatchable generating facility for testing (to assure that such generation facility is available according to the terms of the contract between such generation facility and DWR). The utility will cooperate and shall coordinate with the DWR on a mutually acceptable date for performance of the test. On the date agreed upon, the Utility shall schedule the specified facility or unit for operation to test the availability, reliability, and performance of the scheduled unit.

C. Test Procedures and Protocols

Prior to January 1, 2003, Utility shall meet with DWR staff to review, discuss, and verify test procedures and protocols developed by DWR.

III. Contract Performance Assessments

DWR shall continue to perform an after-the-fact review ("Performance Assessment") of each Contract on a periodic basis. The purpose of the Performance Assessment is to assess, analyze, and document the overall performance of each contract Supplier, assure that the Supplier is satisfying the terms and conditions of their respective contract(s), and identify potential issues, disputes, and other matters that may require corrective action by either Utility or DWR as part of contract administration.

IV. Other Administrative Matters

A. Correspondence with Suppliers

Utility and DWR agree to copy each other on all written correspondence and written notifications sent to or received from a Supplier of an Allocated Contract or Interim Contract related to the activities described in this Exhibit E. The Parties agree to provide additional information as requested related to verification and support of the activities described in this Exhibit E.

B. Reports

Results of the activities described in this Exhibit E will be documented by DWR in written reports ("Reports") and shall be discussed periodically between DWR and the Utility. Such Reports may include, but are not limited to, summary of test results, status of projects, recommendations for operational changes, procedural changes, dispute resolution, and results of Performance Assessments.

Such Reports, documentation, or other material developed by either Party shall be shared and reviewed with the other Party on a timely basis.

DWR/PG&E EXHIBIT F

DWR DATA REQUIREMENTS FROM UTILITY

EXHIBIT F
DWR DATA REQUIREMENTS FROM UTILITY

To effectively fulfill its legal and financial responsibilities, DWR requires access to standard and reliable information on a timely basis. Post transition, DWR remains statutorily and contractually obligated to collect, account for, and remit funds for the power it provides to the IOU's retail customers. More specifically, post transition, DWR must have readily available access to information that is currently available in-house due to DWR's operational responsibilities. The primary source of this information post transition will be the three utilities.

The information being requested is required to:

- Verify, audit, monitor and authorize payment for bilateral invoices for allocated DWR contracts;
- Manage disputes between DWR and the bilateral counterparties;
- Verify, audit, monitor and authorize payment for fuel procured by the utilities relating to DWR allocated contracts;
- Verify, audit, monitor, collect and IOU remittances relating to repayment of Energy Supplied and Bond Funds;
- Forecast, manage and monitor DWR monetary requirements and associated accounts;
- Ongoing reporting responsibilities under AB1X, the rate agreement and bond indenture;
- Audit and monitor long-term contract performance and associated risks prior to contract assignment or novation.

The table below contains a brief description of the information to be provided by Utility, the frequency for which Utility shall provide such information to DWR, and the effective date for when Utility shall provide such information to DWR.

The following table outlines DWR data requirements relating to general contract/trade information:

Contract/Trade

Requirement	Description	Freq	Effective	Delivery Method
Surplus Energy Sales Plan	Monthly utility's surplus energy sales plan updated weekly. Sales plan will outline all surplus sales contemplated by the utility, including but not limited to balance of month, weekly balance of week and other short-term sales.	Monthly plan, updated weekly	1/1/2003	Email/Fax—Standard Form TBD
Surplus Energy Sales	Contract/Deal information relating to the forward sale of DWR surplus energy. This would include but is not limited to Counter party, Term (Start/End Date), Hourly Contract Volumes, Hourly Price, Location, any fee information, etc.	When executed	All surplus forward sales entered into after 1/1/2003	Email/Fax—Standard Form TBD

The following table outlines DWR data requirements relating to long-term contract schedule information and associated bilateral invoices:

Schedule/Bilateral Invoice

Requirement	Description	Freq	Effective	Delivery Method
Final Schedule Volumes, Long Term Contracts	For all long-term contracts allocated to the utilities and any surplus energy sales, the detailed hourly final schedule volumes and pricing information by contract by counterparty, by day. Final schedule volumes are defined as the final volume for the hour at the completion of the real-time market. These volumes represent the hour ahead scheduled volumes adjusted to include any real-time market adjustments by the ISO. Absent any real time adjustments, this data will be the same as Final Hour Ahead Schedule. File should include, but is not limited to; Utility identifier, file type identifier (i.e. final, HA), SC identifier, counterparty identifier, contract identifier, schedule type identifier (i.e. sale), delivery location, date, volume scheduled by hour, price per hour.	T+1 (Daily)	1/2/2003	Secure Electronic— Format TBD
Hour Ahead Schedule Volumes, Long Term Contracts	For all long-term contracts allocated to the utilities and any surplus energy sales, the detailed hour ahead final schedule volumes and pricing information by contract, by counterparty, by day.	T+1 (Daily)	1/2/2003	Secure Electronic— Format TBD

Format and data elements of the file provided should be identical to what was specified above in Final Schedule volumes.

(Note: This cannot be the ISO Hour Ahead Final Schedule template as this file does not provide transactional level details but consolidates/collapses information based on certain ISO rules.)

Reconciled Monthly bilateral invoices	Monthly invoice and supporting documentation for bilateral contracts relating to DWR long-term contracts, reviewed and approved by utility for payment by DWR to the counterparty.	Monthly—5 business days prior to payment due date	Feb 03	TBD

In the event of a bilateral invoice dispute with the counterparty, DWR may also request from the utility the additional schedule information. This information would be in the same format as outlined in the table above. As mentioned above, DWR is requesting transactional level information and not the associated ISO template files due to the consolidation/collapsing of schedules with the template files. Schedule information required would include:

- Hour Ahead Preferred Schedule Volumes
- Day Ahead Final Schedule Volumes
- Day Ahead Adjusted Schedule Volumes
- Day Ahead Revised Preferred Schedule Volumes
- Day Ahead Preferred Schedule Volumes

The following table outlines DWR data requirements relating to the verification of fuel costs. It assumes DWR will retain legal and financial responsibility for gas and related services while the utility will perform administrative and operational responsibilities as outlined in Exhibit B.

Fuel Costs

Requirement	Description	Freq	Effective	Delivery Method
Generator fuel plan proposal	Proposal and supporting analysis on whether or not to accept or reject of generator fuel plan.	Based on individual contracts	Jan-03	TBD
Utility Fuel Procurement Plan	Utility will provide a bi-annual fuel procurement plan for utility supplied fuel.	Bi-Annual	Jan-03	TBD
Tolling agreement Settlement Report	Monthly report on each DWR tolling agreement that includes but is not limited to: tolling contract identifier, who provided the gas (generator/utility) and daily quantity of gas supplied.	Monthly	Feb-03	Electronic Format TBD
Reconciled Monthly Gas Invoice	Suppliers monthly invoice and supporting documentation for fuel procurement relating to DWR tolling agreements, reviewed and approved by Utility for payment by DWR to the supplier.	Monthly—5-business days prior to payment due date	Feb-03	Electronic—Format TBD
Gas Transportation Contract Information	Details relating to the Utility negotiated firm and/or interruptible transportation agreements for DWR review and authorization.	When executed	All contracts effective after 1/1/2003	E-mail/Fax Standard Form TBD
Gas Storage Contract Information	Details relating to the Utility/negotiated firm and/or interruptible storage agreements for DWR review and authorization.	When executed	All contracts effective after 1/1/03	E-mail/Fax Standard Form TBD
Reconciled Monthly gas transportation invoices	Suppliers monthly invoice and supporting documentation for natural gas transportation costs relating to DWR tolling agreements, reviewed and approved by utility for payment by DWR to the supplier.	Monthly—5-business days prior to payment due date	Feb-03	Electronic—Format TBD

Reconciled Monthly gas storage invoices	Supplier's monthly invoice and supporting documentation for storage relating to DWR tolling agreements, reviewed and approved by utility for payment by DWR to the supplier.	Monthly—5-business days prior to payment due date	Feb-03	Electronic—Format TBD

The following table outlines additional DWR data relating to utility revenue remittance:

Utility Revenue Remittance

Requirement	Description	Freq	Effective	Delivery Method
Utility ISO Preliminary Settlement and Supporting Files	The complete Utility preliminary settlement statement and supporting files in original ISO template format.	T + 38 business days	Ongoing	Secure Electronic-ISO Template Direct from ISO
Utility Final ISO Settlement Statement and Supporting Files	The complete Utility final ISO settlement statement and supporting files in ISO original template format. This information also required for remittance calculation purposes.	T + 45 business days	Ongoing	Secure Electronic-ISO Template Direct from ISO
Scheduled Retail Load by hour	Utilities estimated retail load information by hour, by day used for the preliminary remittance.	T + 1	1/1/2003	TBD
Hourly aggregate final schedule of Utility's resource portfolio	Utilities total hourly scheduled volumes for the entire Utilities portfolio. This is an aggregate total for the day, by hour and represents the total volume supplied by the utility.	T+1 (Daily)	1/2/2003	TBD
Wholesale Obligation Volumes	Utilities total hourly scheduled volumes for pre-existing wholesale commitments in aggregate by the hour for each day.	T+1 (Daily)	1/2/03	TBD
Hourly Distribution Loss Factor	Utility DLF % by hour	When changes required	1/1/2003	TBD
Estimated DWR remittance %	Utility estimated remittance percentage.	When changes required	1/1/2003	TBD
Energy Sales billed (kWh)*	Monthly kWh billed by Utility to end users	Monthly	Ongoing	Standard DWR Form/File (TBD)
DWR Power Charge volumes*	Monthly kWh billed by Utility to end users	Monthly	Ongoing	Standard DWR Form/File (TBD)

DWR Power Charge billed to Customer*	Monthly dollar amount of DWR Power Charge being billed to customer including identification of dates billed.	Monthly	Ongoing	Standard DWR Form/File
DWR Power Charge Remitted to DWR*	Daily dollar amount being remitted by Utility to DWR for the DWR Power Charge collected from customers including identification of dates billed.	Daily	Ongoing	Standard DWR Form/File (TBD)

* This information is already provided pursuant to the Servicing Arrangement, and supports the daily remittance calculation for each month and subsequent true-ups. The Servicing Arrangement will be modified as necessary to conform to this Operating Agreement.

As various Commission proceedings are finalized DWR will also require specific data related to Bond Charge remittances and to Direct Access exit fees. The specific nature and format of this data will be agreed with between the utilities and DWR.

The following table outlines DWR data requirements relating to resource information:

Resource Information

Requirement	Description	Freq	Effective	Delivery Method
Load and Resource Assessment Studies	Copies of Utilities annual and quarter load and resource assessment studies as provided to the PUC.	Annually and quarterly	Jan-03	TBD
Update Description of Resources	Updated description of URG resources.	Annually or when significant changes	Jan 1, 04	TBD
Unit Commitment Studies	As provided to the PUC.	Weekly	Jan-03	TBD
DWR Non-Dispatched Resources Report	Report of Resources that were economic to run, but were not dispatched.	Ad hoc	1/1/03	TBD
DWR Resource Unavailability Form	Utility notification to DWR for resources within an allocated contracts becoming unavailable, or scheduled to become unavailable. Note: This information could be provided directly from the generator to DWR and would therefore not be required from Utility.	As outlined in operating agreement	1/1/2003	Standard DWR Form— Email/Fax

Upon the reasonable request of DWR, Utility will provide to DWR any information in respect of Utility that is applicable to the rights and obligations of the Parties under this Agreement or any material information that is reasonably necessary for DWR to monitor and manage their risks and perform their fiduciary responsibilities. Upon the reasonable request of Utility, DWR will provide to Utility any information in respect of DWR that is applicable to the rights and obligations of the Parties under this Agreement or any material information that is reasonably necessary for Utility to operationally administer Contracts under this Agreement.

For the information identified above, or any additional information identified through the term of this Agreement, standard submission formats will be used or be developed by DWR for use by each of the investor-owned utilities, including Utility. In the cases where the information requirements result in a large volume of data (e.g., schedule information), DWR will use or develop standard detailed file definitions for use by all of the investor-owned utilities, including Utility. Data will be submitted to DWR by Utility through a secure electronic communication medium, unless other medium is reasonably requested by DWR.

As a result of the relative short implementation timeframes, it is anticipated an interim delivery protocol (e.g., comma delimited file via email, compact diskettes) will be utilized until the final data

transmission media are in place. DWR shall work jointly with Utility to ensure the required data is available by January 1, 2003.

In the event that DWR incurs additional costs, including but not limited to penalties, interest or other such costs, due to Utility's failure to timely provide the data set forth in this Exhibit F, any such direct cost increase invoiced or assessed to DWR shall be borne by Utility.

The provisions of this Exhibit are subject to annual review by DWR and Utility to ensure that data reporting remains relevant and useful.

Exhibit 10.9

OPERATING AGREEMENT Between
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OPERATING AGREEMENT
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ARTICLE II OPERATIONAL ALLOCATION OF POWER PURCHASE AGREEMENTS; MANAGEMENT OF THE CONTRACTS;
ALLOCATED POWER; TERM
ARTICLE III LIMITED AGENCY / NO ASSIGNMENT
ARTICLE IV LIMITED DUTIES OF UTILITY
ARTICLE V DUTIES OF DWR
ARTICLE VI SPECIAL CONTRACT TERMS
ARTICLE VII EVENTS OF DEFAULT
ARTICLE VIII PAYMENT OF FEES AND CHARGES
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ALLOCATED CONTRACTS
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REPRESENTATIVES AND CONTACTS
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EXHIBIT A OPERATING PROTOCOLS
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EXHIBIT B FUEL MANAGEMENT PROTOCOLS
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EXHIBIT C SETTLEMENT PRINCIPLES FOR REMITTANCES AND SURPLUS REVENUES
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EXHIBIT F DWR DATA REQUIREMENTS FROM UTILITY

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Exhibit 10.10

**PG&E CORPORATION
SUPPLEMENTAL RETIREMENT SAVINGS PLAN**

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PG&E CORPORATION
SUPPLEMENTAL RETIREMENT SAVINGS PLAN

This is the controlling and definitive statement of the PG&E CORPORATION ("PG&E CORP") Supplemental Retirement Savings Plan (the "Plan"). Except as provided herein, the Plan is effective as of January 1, 2000, with respect to all individuals who were Eligible Employees as of such date. The Plan takes the place of and assumes existing benefits under the PG&E Corporation Deferred Compensation Plan for Officers, the PG&E Corporation Supplemental Executive Retirement Plan, the Savings Fund Plan Excess Benefit Arrangement of Pacific Gas and Electric Company, and any other non-qualified defined contribution retirement plan excess benefit plans, programs or practices maintained by any Participating Subsidiary of PG&E CORP. The Plan as originally adopted was effective January 1, 2000, for Eligible Employees of Pacific Gas and Electric Company and for Grandfathered Eligible Employees of PG&E CORP; it was effective January 1, 1999, for Eligible Employees of PG&E Generating Company; and it was effective January 1, 1997, for all other Eligible Employees of PG&E CORP. The Plan as amended herein is effective September 19, 2001. The Plan is frozen as to amounts "deferred" within the meaning of Code Section 409A after December 31, 2004.

1. *Purpose of the Plan .*

The Plan is established and is maintained for the benefit of a select group of management and highly compensated employees of PG&E CORP and its Participating Subsidiaries in order to provide such employees with certain deferred compensation benefits. The Plan is an unfunded deferred compensation plan that is intended to qualify for the exemptions provided in Sections 201, 301, and 401 of ERISA.

2. *Definitions .*

The following words and phrases shall have the following meanings unless a different meaning is plainly required by the context:

- (a) " *Basic Employer Contributions* " shall mean the amounts credited to Eligible Employees' Accounts under the Plan by the Employers, in accordance with Section 3(c).
 - (b) " *Board of Directors* " shall mean the Board of Directors of PG&E CORP, as from time to time constituted.
 - (c) " *Code* " shall mean the Internal Revenue Code of 1986, as amended. Reference to a specific section of the Code shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.
 - (d) " *Committee* " shall mean the Nominating and Compensation Committee of the Board, as it may be constituted from time to time.
 - (e) " *Eligible Employee* " shall mean an Employee who:
 - (1) Is an officer of PG&E CORP or any Participating Subsidiary and who is in Officer Band 5 or above; or
 - (2) Is a key employee of PG&E CORP or any Participating Subsidiary and who is designated by the Plan Administrator as eligible to participate in the Plan.
 - (f) " *Eligible Employee's Account* " or " *Account* " shall mean as to any Eligible Employee, the separate account maintained on the books of the Employer in accordance with Section 6(a) in order to reflect his or her interest under the Plan. Accounts shall be centrally administered by the Plan Administrator or its designee.
 - (g) " *Employee* " shall mean an individual who is treated in the records of an Employer as an employee of the Employer, who is not on an unpaid leave of absence, and/or who is not covered by a collective bargaining agreement; provided, however, such term shall not mean an individual who is a "leased employee" or who has entered into a written contract or agreement with an Employer which explicitly excludes such individual from participation in an
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Employer's benefit plans. The provisions of this definition shall govern, whether or not it is determined that an individual otherwise meets the definition of "common law" employee.

- (h) "*Employers*" shall mean PG&E CORP and the Participating Subsidiaries designated by the Employee Benefit Committee of PG&E CORP. An initial list of the Participating Subsidiaries is contained in Appendix A to this Plan.
- (i) "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended. Reference to a specific section of ERISA shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.
- (j) "*Grandfathered*" shall mean an individual who was an Employee of Pacific Gas and Electric Company and who has become an Employee of PG&E CORP by reason of a transfer prior to January 1, 2000.
- (k) "*Investment Funds*" shall mean (i) the PG&E CORP Phantom Stock Fund, (ii) the AA Utility Bond Fund, and (iii) the S&P 500 Index Fund. The Investment Funds shall be used for tracking phantom investment results under the Plan.
- (l) "*Matching Employer Contributions*" shall mean the amounts credited to Eligible Employees' Accounts under the Plan by the Employers, in accordance with Section 3(b).
- (m) "*Participating Subsidiary*" shall mean a United States-based subsidiary of PG&E CORP, which has been designated by the Employee Benefit Committee of PG&E CORP as a Participating Subsidiary under this Plan. At such times and under such conditions as the Committee may direct, one or more other subsidiaries of PG&E CORP may become Participating Subsidiaries or a Participating Subsidiary may be withdrawn from the Plan. An initial list of the Participating Subsidiaries is contained in Appendix A to this Plan.
- (n) "*PG&E CORP*" shall mean PG&E Corporation, a California corporation.
- (o) "*Plan*" shall mean the PG&E Corporation Supplemental Retirement Savings Plan, as set forth in this instrument and as heretofore and hereafter amended from time to time.
- (p) "*Plan Year*" shall mean the calendar year.
- (q) "*Retirement*" or "*Retire*" shall mean an Eligible Employee's "separation from service" within the meaning of Section 401(k) of the Code, provided that the Eligible Employee is at least 55 years of age and has been employed by an Employer for at least five years.
- (r) "*RSP*" shall mean, with respect to any Eligible Employee, the PG&E Corporation Retirement Savings Plan or any predecessor qualified retirement plan sponsored by PG&E CORP or any of its subsidiary companies.
- (s) "*Valuation Date*" shall mean:
 - (1) For purposes of valuing Plan assets and Eligible Employees' Accounts for periodic reports and statements, the date as of which such reports or statements are made; and
 - (2) For purposes of determining the amount of assets actually distributed to the Eligible Employee, his or her beneficiary, or an Alternate Payee (or available for withdrawal), a date that shall not be more than seven business days prior to the date the check is issued to the Eligible Employee.

In any other case, the Valuation Date shall be the date designated by the Plan Administrator (in its discretion) or the date otherwise set forth in this Plan. In all cases, the Plan Administrator (in its

discretion) may change the Valuation Date, on a uniform and nondiscriminatory basis, as is necessary or appropriate. Notwithstanding the foregoing, the Valuation Date shall occur at least annually.

3. *Employer Contributions .*

- (a) *Matching Employer Contributions .* Subject to the provisions of Section 13, the Eligible Employee's Account shall be credited for each Plan Year with a Matching Employer Contribution, calculated in the manner provided in Sections 3(a) (1), (2), and (3) below:
 - (1) First, an amount shall be calculated equal to the maximum matching contribution that would be made under the terms of the RSP, taking into account for such Plan Year the amount of pre-tax deferrals and after-tax contributions the Eligible Employee elected under the RSP. For purposes of this calculation, any amounts deferred under Subsection 4(a) of this Plan shall be treated as pre-tax deferrals under the RSP.
 - (2) The calculation made in accordance with this Section 3(a) (1) above shall be made without regard to any limitation on such amounts under the RSP resulting from the application of any of the limitations under Code Sections 401(m), 401(a)(17), or 415.
 - (3) The Employer Matching Contribution to be credited to the Account of an Eligible Employee for any Plan Year shall equal the amount calculated in accordance with Sections 3(a) (1) and (2) above, reduced by the amount of matching contribution made to such Eligible Employee's account for such Plan Year under the RSP.
- (b) *Crediting of Matching Employer Contributions .* Matching Employer Contributions shall be calculated and credited to the Eligible Employee's Account as of the first business day of the calendar year following the Plan Year and shall be credited only if the Eligible Employee is an Employee on the last day of Plan Year for which the amounts are credited.
- (c) *Basic Employer Contributions .* Subject to the provisions of Section 13, the Account of each Eligible Employee shall be credited for each Plan Year with a Basic Employer Contribution, calculated in the manner provided in Sections 3(c) (1), (2), and (3) below:
 - (1) First, an amount shall be calculated equal to the Basic Employer Contribution that would be made under the terms of the RSP, taking into account for such Plan Year the Eligible Employee's Covered Compensation under the RSP, before any deductions for compensation deferrals elected by such Eligible Employee under Subsection 4(a) of this Plan. For Eligible Employees as defined by Section 2(e)(1) of this Plan, compensation shall also reflect such Eligible Employee's Short-Term Incentive Plan awards.
 - (2) The calculation made in accordance with this Section 3(c)(1) above shall be made without regard to any limitation on such amounts under the RSP resulting from the application of any of the limitations under Code Sections 401(a)(4), 401(a)(17), or 415.
 - (3) The Employer Contribution to be credited to the Account of an Eligible Employee for any Plan Year shall equal the amount calculated in accordance with Sections 3(c)(1) and (2) above, reduced by the amount of Basic Employer Contributions made to such Eligible Employee's account for such Plan Year under the RSP.
- (d) *Crediting of Basic Employer Contributions .* The Employer Contribution attributable to an Eligible Employee's Short Term Incentive Plan award shall be credited to an Eligible Employee's Account as of the first business day of the month following the date on which the Short-Term Incentive Plan award is paid. All other Employer Contributions made in respect of an Eligible Employee shall be credited to the Eligible Employee's Account as of the first business day of the calendar year following the Plan Year and shall be credited only if the Eligible Employee is an Employee on the last day of the Plan Year for which the amounts are credited.

- (e) *FICA Taxes* . Each Eligible Employee shall be responsible for FICA taxes on amounts credited to his or her Account under Sections 3 and 4(d).
4. *Eligible Employee Deferrals* .
- (a) *Amount of Deferral* . An Eligible Employee may defer (i) 5 percent to 50 percent of his or her annual salary; and (ii) all or part of his or her Short Term Incentive Plan awards, Long-Term Incentive Plan (LTIP) awards (other than stock options), Perquisite Allowances, and any other special payments, awards, or bonuses as authorized by the Plan Administrator.
 - (b) *Credits to Accounts* . Salary deferrals shall be credited to an Eligible Employee's Account as of each payroll period. All other deferrals attributable to allowances, awards, bonuses, and other payments shall be credited as of the date that they otherwise would have been paid.
 - (c) *Deferral Election* . An Eligible Employee must file an election form with the Plan Administrator which indicates the percentage of salary and applicable pay periods, and the amount of any awards, allowances, payments, and bonuses to be deferred under the Plan. Notwithstanding the foregoing, upon first becoming an Eligible Employee, an election to defer shall be effective for the month following the filing of a Deferral Election Form, provided said Form is filed within 60 days following the date when the employee first becomes an Eligible Employee.
 - (d) *Deferral of Special Incentive Stock Ownership Premiums* . All of an Eligible Employee's Special Incentive Stock Ownership Premiums are automatically deferred to the Plan immediately upon grant and converted into units in the PG&E CORP Phantom Stock Fund. The units attributable to Special Incentive Stock Ownership Premiums and any additional units resulting from the conversion of dividend equivalents thereon remain unvested until the earlier of the third anniversary of the date on which the Special Incentive Stock Ownership Premiums are credited to an Eligible Employee's account (provided the Eligible Employee continues to be employed on such date), death, disability, or retirement of the participant, or upon a Change in Control as defined in the LTIP. (The term "disability" shall, for purposes of the Plan, have the same meaning as in Section 22(e)(3) of the Internal Revenue Code.) Unvested units attributable to Special Incentive Stock Ownership Premiums and any additional units resulting from the conversion of dividend equivalents thereon shall be forfeited upon termination of the Eligible Employee's employment unless otherwise provided in the PG&E Corporation Executive Stock Ownership Program or if an Eligible Employee's stock ownership falls below the levels set forth in the Executive Stock Ownership Program.
5. *Investment Funds* .
- (a) Although no assets will be segregated or otherwise set aside with respect to an Eligible Employee's Account, the amount that is ultimately payable to the Eligible Employee with respect to such Account shall be determined as if such Account had been invested in some or all of the Investment Funds. The Plan Administrator, in its sole discretion, shall adopt (and modify from time to time) such rules and procedures as it deems necessary or appropriate to implement the deemed investment of the Eligible Employees' Accounts. Such procedures generally shall provide that an Eligible Employee's Account shall be deemed to be invested among the three Investment Funds in the manner elected by the Eligible Employee in such percentages and manner as prescribed by the Plan Administrator. In the event no election has been made by the Eligible Employee, such Account will be deemed to be invested in the AA Utility Bond Fund. Eligible Employees shall be able to reallocate their Accounts between the Investment Funds and reallocate amounts newly credited to their Accounts at such time and in such manner as the Plan Administrator shall prescribe. Anything to the contrary herein notwithstanding, an Eligible Employee may not reallocate Account balances between Investment Funds if such reallocation would result in a non-exempt Discretionary Transaction

as defined in Rule 16b-3 of the Securities Exchange Act of 1934, as amended, or any successor to Rule 16b-3, as in effect when the reallocation is requested.

- (1) AA Utility Bond Fund. Interest shall be credited on the amounts invested in the AA Utility Bond Fund. Such interest shall be at a rate equal to the AA Utility Bond Yield reported by *Moody's Investors Service*. Such interest shall become a part of the Eligible Employee's Account and shall be paid at the same time or times as the balance of the Eligible Employee's Account.
- (2) PG&E CORP Phantom Stock Fund. Amounts credited to the PG&E CORP Phantom Stock Fund shall be converted into units (including fractions computed to three decimal places) each representing a share of PG&E CORP common stock. The value of a unit for purposes of determining the number of units to credit upon initial allocation or upon reallocation from another Investment Fund, and for determining the dollar value of the aggregate number of units to be reallocated from the PG&E CORP Phantom Stock Fund to another Investment Fund and for distributions from the Plan, shall be the closing price of a share of PG&E CORP common stock as traded on the New York Stock Exchange on the date that (i) amounts are credited to an Eligible Employee's Account in the PG&E CORP Phantom Stock Fund, or (ii) the Plan Administrator receives a reallocation request, in the case of reallocations. If such credit or reallocation occurs after close of the New York Stock Exchange on that day, the price shall be based on the closing price of a share of PG&E CORP common stock on the next day on which such shares are traded on the New York Stock Exchange. Thereafter, the value of a unit shall fluctuate in accordance with the closing price of PG&E CORP common stock on the New York Stock Exchange. Each time that PG&E CORP pays a dividend on its common stock, an amount equal to such dividend payable with respect to each share of PG&E CORP common stock, multiplied by the number of units credited to an Eligible Employee's Account, shall be credited to the Eligible Employee's Account and converted into additional units. The number of additional units shall be calculated by dividing the aggregate amount of credited dividends, *i.e.*, the dividend multiplied by the number of units credited to the Eligible Employee's Account as of the dividend record date, by the closing price of a share of PG&E CORP common stock on the New York Stock Exchange on the dividend payment date. If, after the record date but before the dividend payment date, an Eligible Employee's balance in the PG&E CORP Phantom Stock Fund has been reallocated to another Investment Fund(s) or has been paid to the Eligible Employee or to the Eligible Employee's beneficiary, other than pursuant to an election under Sections 7(c)(2) or 8, then an amount equal to the aggregated dividend shall be credited to the Eligible Employee's Account in such other Investment Fund(s) or paid directly to the Eligible Employee or the Eligible Employee's beneficiary, whichever is applicable.
- (3) S&P 500 Index Fund. Amounts credited to the S&P 500 Index Fund shall be converted into units each representing a Large Company Stock Fund (LCSF) unit held in the RSP on the date of allocation. Thereafter, the value of a unit held in the S&P Index Fund shall be determined in the same manner as the value of a LCSF unit under Section 18 of the RSP.

6. *Accounting*.

- (a) *Eligible Employees' Accounts*. At the direction of the Plan Administrator, there shall be established and maintained on the books of the Employer, a separate account for each Eligible Employee in order to reflect his or her interest under the Plan.
- (b) *Investment Earnings*. Each Eligible Employee's Account shall initially reflect the value of his or her Account's interest in each of the Investment Funds, deemed acquired with the amounts

credited thereto. Each Eligible Employee's Account shall also be credited (or debited) with the net appreciation (or depreciation), earnings and gains (or losses) with respect to the investments deemed made by his or her Account. Any such net earnings or gains deemed realized with respect to any investment of any Eligible Employee's Account shall be deemed reinvested in additional amounts of the same investment and credited to the Eligible Employee's Account.

- (c) *Accounting Methods* . The accounting methods or formulae to be used under the Plan for the purpose of maintaining the Eligible Employees' Accounts shall be determined by the Plan Administrator. The accounting methods or formulae selected by the Plan Administrator may be revised from time to time but shall conform to the extent practicable with the accounting methods used under the Applicable Plan.
- (d) *Valuations and Reports* . The fair market value of each Eligible Employee's Account shall be determined as of each Valuation Date. In making such determinations and in crediting net deemed earnings and gains (or losses) in the Investment Funds to the Eligible Employees' Accounts, the Plan Administrator (in its discretion) may employ such accounting methods as the Plan Administrator (in its discretion) may deem appropriate in order to fairly reflect the fair market values of the Investment Funds and each Eligible Employee's Account. For this purpose, the Plan Administrator may rely upon information provided by the Plan Administrator or other persons believed by the Plan Administrator to be competent.
- (e) *Statements of Eligible Employee's Accounts* . Each Eligible Employee shall be furnished with periodic statements of his or her interest in the Plan.

7. *Distributions* .

- (a) *Distribution of Account Balances* . Unless the Eligible Employee has elected otherwise under this Section 7, distribution of the balance credited to an Eligible Employee's Account shall be made in a single sum in the January of the year following Retirement or termination of service:
 - (1) In the case of an Alternate Payee (as defined in Section 9(a)), distribution shall be made as directed in a domestic relations order which the Plan Administrator determines is a QDRO (as defined in Section 9(a)), but only as to the portion of the Eligible Employee's Account which the QDRO states is payable to the Alternate Payee.
 - (2) Any provisions of the Plan notwithstanding distribution of account balances must commence no later than in the January following the year which the Eligible Employee reaches age 72.
- (b) *Installment Distributions* . In lieu of a single sum payment, an Eligible Employee whose Account value (exclusive of Special Incentive Stock Ownership Premiums) is at least \$5,000 may elect in writing and file with the Plan Administrator an election that payment of amounts credited to the Eligible Employee's Account be made in a specified number of approximately equal annual installments (not in excess of 10). However, if during the installment payment period the Account balance, exclusive of Special Incentive Stock Ownership Premiums, is less than \$5,000, the value of the remaining installments shall be paid as a lump sum. All installment payments will be made during the month of January.

- (c) *Early Distributions* . By filing an irrevocable election with the Plan Administrator, an Eligible Employee may elect to commence distribution of full or partial payment at any time other than Retirement or termination, provided that:
- (1) such election is made at least one year prior to the Retirement or termination of the Eligible Employee and does not provide for the receipt of such amounts earlier than one year from the date of the election; or
 - (2) the Eligible Employee elects to forfeit 10 percent of the value of the requested distribution, valued as of the new date for distribution of such Account funds, and such Eligible Employee shall not be permitted to make future deferrals for 24 months following such distribution.

All early distributions elected pursuant to Section 7(c)(1) must be made during the month of January.

- (d) *Death Distributions* . If an Eligible Employee dies before the entire balance of his or her Account has been distributed (whether or not the Eligible Employee had previously terminated employment and whether or not installment payments had previously commenced), the remaining balance of the Eligible Employee's Account shall be distributed to the beneficiary designated or otherwise determined in accordance with Section 7(h), as soon as practicable after the date of death.
- (e) *Special Incentive Stock Ownership Premiums* . Distributions attributable to Special Incentive Stock Ownership Premiums shall only be made in January following the year in which an Eligible Employee terminates employment, Retires, or dies, and shall only be made in the form of one or more certificates for the number of vested Special Incentive Stock Ownership Premium units, rounded down to the nearest whole share.
- (f) *Effect of Change in Eligible Employee Status* . If an Eligible Employee ceases to be an Eligible Employee, the balance credited to his or her Account shall continue to be credited (or debited) with appreciation, depreciation, earnings, gains or losses under the terms of the Plan and shall be distributed to him or her at the time and in the manner set forth in this Section 7; provided, however, that if an Eligible Employee terminates employment with an Employer other than by reason of Retirement, the entire balance credited to his or her Account shall be distributed in a lump sum cash payment in January of the year following the year of termination of employment. Anything to the contrary notwithstanding, the Plan Administrator, in its sole discretion, may authorize an accelerated distribution of the balance credited to his or her Account in the form of a lump sum cash payment as of any earlier date.
- (g) *Payments to Incompetents* . If any individual to whom a benefit is payable under the Plan is a minor or if the Plan Administrator determines that any individual to whom a benefit is payable under the Plan is incompetent to receive such payment or to give a valid release therefor, payment shall be made to the guardian, committee, or other representative of the estate of such individual which has been duly appointed by a court of competent jurisdiction. If no guardian, committee, or other representative has been appointed, payment may be made to any person as custodian for such individual under the California Uniform Transfers to Minors Act (or similar law of another state) or may be made to or applied to or for the benefit of the minor or incompetent, the incompetent's spouse, children or other dependents, the institution or persons maintaining the minor or incompetent, or any of them, in such proportions as the Plan Administrator from time to time shall determine; and the release of the person or institution receiving the payment shall be a valid and complete discharge of any liability of PG&E CORP with respect to any benefit so paid.

- (h) *Beneficiary Designations* . Each Eligible Employee may designate, in a signed writing delivered to the Plan Administrator, on such form as it may prescribe, one or more beneficiaries to receive any distribution which may become payable under the Plan as the result of the Eligible Employee's death. An Eligible Employee may designate different beneficiaries at any time by delivering a new designation in like manner. Any designation shall become effective only upon its receipt by the Plan Administrator, and the last effective designation received by the Plan Administrator shall supersede all prior designations. If an Eligible Employee dies without having designated a beneficiary or if no beneficiary survives the Eligible Employee, the Eligible Employee's Account shall be payable to the beneficiary or beneficiaries designated or otherwise determined under the RSP.
- (i) *Undistributable Accounts* . Each Eligible Employee and (in the event of death) his or her beneficiary shall keep the Plan Administrator advised of his or her current address. If the Plan Administrator is unable to locate the Eligible Employee or beneficiary to whom an Eligible Employee's Account is payable under this Section 7, the Eligible Employee's Account shall be frozen as of the date on which distribution would have been completed in accordance with this Section 7, and no further appreciation, depreciation, earnings, gains or losses shall be credited (or debited) thereto. PG&E CORP shall have the right to assign or transfer the liability for payment of any undistributable Account to the Eligible Employee's former Employer (or any successor thereto).
- (j) *Plan Administrator Discretion* . Within the specific time periods described in this Section 7, the Plan Administrator shall have sole discretion to determine the specific timing of the payment of any Account balance under the Plan.

8. *Distribution Due to Unforeseeable Emergency (Hardship Distribution)*

A participant may request a distribution due to an unforeseeable emergency by submitting a written request to the Plan Administrator. The Plan Administrator shall have the authority to require such evidence as it deems necessary to determine if a distribution is warranted. If an application for a hardship distribution due to an unforeseeable emergency is approved, the distribution shall be payable in a method determined by the Plan Administrator as soon as possible after approval of such distribution. After receipt of a payment requested due to an unforeseeable emergency, a participant may not make additional deferrals during the remainder of the Plan Year in which the recipient received the payment. A participant who has commenced receiving installment payments under the Plan may request acceleration of such payments in the event of an unforeseeable emergency. The Administrator may permit accelerated payments to the extent such accelerated payment does not exceed the amount necessary to meet the emergency.

9. *Domestic Relations Orders*

- (a) *Qualified Domestic Relations Orders* . The Plan Administrator shall establish written procedures for determining whether a domestic relations order purporting to dispose of any portion of an Eligible Employee's Account is a qualified domestic relations order (within the meaning of Section 414(p) of the Code) (a " QDRO ").
 - (1) *No Payment Unless a QDRO*. No payment shall be made to any person designated in a domestic relations order (an " *Alternate Payee* ") until the Plan Administrator (or a court of competent jurisdiction reversing an initial adverse determination by the Plan Administrator) determines that the order is a QDRO. Payment shall be made to each Alternate Payee as specified in the QDRO.
 - (2) *Time of Payment* . Payment may be made to an Alternate Payee in the form of a lump sum, at the time specified in the QDRO, but no earlier than as soon as practicable following the date the QDRO determination is made.

- (3) *Hold Procedures* . Notwithstanding any contrary Plan provision, prior to the receipt of a domestic relations order, the Plan Administrator may, in its sole discretion, place a hold upon all or a portion of an Eligible Employee's Account for a reasonable period of time (as determined by the Plan Administrator) if the Plan Administrator receives notice that (a) a domestic relations order is being sought by the Eligible Employee, his or her spouse, former spouse, child or other dependent, and (b) the Eligible Employee's Account is a source of the payment under such domestic relations order. For purposes of this Section 9(a)(3), a " *hold* " means that no withdrawals, distributions, or investment transfers may be made with respect to an Eligible Employee's Account. If the Plan Administrator places a hold upon an Eligible Employee's Account pursuant to this Section 9(a)(3), it shall inform the Eligible Employee of such fact.

10. *Vesting*

Except as provided in Section 4(d), an Eligible Employee's interest in his or her Account at all times shall be 100 percent vested and nonforfeitable.

11. *Administration of the Plan*

- (a) *Plan Administrator* . The Employee Benefit Committee of PG&E CORP is hereby designated as the administrator of the Plan (within the meaning of Section 3(16)(A) of ERISA). The Plan Administrator delegates to the Senior Human Resource Officer for PG&E CORP, or his or her designee, the authority to carry out all duties and responsibilities of the Plan Administrator under the Plan. The Plan Administrator shall have the authority to control and manage the operation and administration of the Plan.
- (b) *Powers of Plan Administrator* . The Plan Administrator shall have all discretion and powers necessary to supervise the administration of the Plan and to control its operation in accordance with its terms, including, but not by way of limitation, the power to interpret the provisions of the Plan and to determine, in its sole discretion, any question arising under, or in connection with the administration or operation of, the Plan.
- (c) *Decisions of Plan Administrator* . All decisions of the Plan Administrator and any action taken by it in respect of the Plan and within the powers granted to it under the Plan shall be conclusive and binding on all persons and shall be given the maximum deference permitted by law.

12. *Funding*

All amounts credited to an Eligible Employee's Account under the Plan shall continue for all purposes to be a part of the general assets of PG&E CORP. The interest of the Eligible Employee in his or her Account, including his or her right to distribution thereof, shall be an unsecured claim against the general assets of PG&E CORP. While PG&E CORP may choose to invest a portion of its general assets in investments identical or similar to those selected by Eligible Employees for purposes of determining the amounts to be credited (or debited) to their Accounts, nothing contained in the Plan shall give any Eligible Employee or beneficiary any interest in or claim against any specific assets of PG&E CORP.

13. *Modification or Termination of Plan*

- (a) *Employers' Obligations Limited* . The Plan is voluntary on the part of the Employers, and the Employers do not guarantee to continue the Plan. PG&E CORP at any time may, by appropriate amendment of the Plan, suspend Matching Employer Contributions and/or Basic Employer Contributions or may discontinue Matching Employer Contributions and/or Basic Employer Contributions, with or without cause.

- (b) *Right to Amend or Terminate* . The Board of Directors, acting through its Nominating and Compensation Committee, reserves the right to alter, amend, or terminate the Plan, or any part thereof, in such manner as it may determine, for any reason whatsoever.
- (1) *Limitations* . Any alteration, amendment, or termination shall take effect upon the date indicated in the document embodying such alteration, amendment, or termination, provided that no such alteration or amendment shall divest any portion of an Account that is then vested under the Plan.
- (c) *Effect of Termination* . If the Plan is terminated, the balances credited to the Accounts of the Eligible Employees affected by such termination shall be distributed to them at the time and in the manner set forth in Section 7; provided, however, that the Plan Administrator, in its sole discretion, may authorize accelerated distribution of Eligible Employees' Accounts as of any earlier date.

14. *General Provisions*

- (a) *Inalienability* . Except to the extent otherwise directed by a domestic relations order which the Plan Administrator determines is a QDRO (as defined in Section 9(a) or mandated by applicable law, in no event may either an Eligible Employee, a former Eligible Employee or his or her spouse, beneficiary or estate sell, transfer, anticipate, assign, hypothecate, or otherwise dispose of any right or interest under the Plan; and such rights and interests shall not at any time be subject to the claims of creditors nor be liable to attachment, execution, or other legal process.
- (b) *Rights and Duties* . Neither the Employers nor the Plan Administrator shall be subject to any liability or duty under the Plan except as expressly provided in the Plan, or for any action taken, omitted, or suffered in good faith.
- (c) *No Enlargement of Employment Rights* . Neither the establishment or maintenance of the Plan, the making of any Matching Employer Contributions, nor any action of any Employer or Plan Administrator, shall be held or construed to confer upon any individual any right to be continued as an Employee nor, upon dismissal, any right or interest in any specific assets of the Employers other than as provided in the Plan. Each Employer expressly reserves the right to discharge any Employee at any time, with or without cause or advance notice.
- (d) *Apportionment of Costs and Duties* . All acts required of the Employers under the Plan may be performed by PG&E CORP for itself and its Participating Subsidiaries, and the costs of the Plan may be equitably apportioned by the Plan Administrator among PG&E CORP and the other Employers. Whenever an Employer is permitted or required under the terms of the Plan to do or perform any act, matter or thing, it shall be done and performed by any officer or employee of the Employer who is thereunto duly authorized by the board of directors of the Employer.
- (e) *Applicable Law* . The provisions of the Plan shall be construed, administered, and enforced in accordance with the laws of the State of California and, to the extent applicable, ERISA.
- (f) *Severability* . If any provision of the Plan is held invalid or unenforceable, its invalidity or unenforceability shall not affect any other provisions of the Plan, and the Plan shall be construed and enforced as if such provision had not been included.
- (g) *Captions* . The captions contained in and the table of contents prefixed to the Plan are inserted only as a matter of convenience and for reference and in no way define, limit, enlarge, or describe the scope or intent of the Plan nor in any way shall affect the construction of any provision of the Plan.

APPENDIX A
PARTICIPATING SUBSIDIARIES

Participating Subsidiaries as of January 1, 1997

- PG&E Gas Transmission Corporation
- PG&E Gas Transmission, Texas Corporation
- PG&E Gas Transmission TECO, Inc.
- PG&E Energy Trading-Gas Corporation
- PG&E Energy Services Corporation
- And the U.S. subsidiaries of each of the above-named corporations.

Additional Participating Subsidiaries as of January 1, 1998

- PG&E Corporation
- Pacific Gas and Electric Company
- PG&E Generating Company
- PG&E Corporation Support Services, Inc.
- And the U.S. subsidiaries of each of the above-named corporations.

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Exhibit 10.10

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**PG&E CORPORATION
2005 SUPPLEMENTAL RETIREMENT SAVINGS PLAN**

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PG&E CORPORATION
2005 SUPPLEMENTAL RETIREMENT SAVINGS PLAN

This is the controlling and definitive statement of the PG&E CORPORATION ("PG&E CORP") 2005 Supplemental Retirement Savings Plan (the "Plan"). Except as provided herein, the Plan is effective as of January 1, 2005, with respect to all individuals who are Eligible Employees as of such date. The Plan continues the benefit program embodied in the PG&E Corporation Supplemental Retirement Savings Plan (the "Prior Plan"). Benefits accrued under the Prior Plan continue to be payable under the Prior Plan pursuant to the terms and conditions of the Prior Plan.

1. *Purpose of the Plan*

The Plan is established and is maintained for the benefit of a select group of management and highly compensated employees of PG&E CORP and its Participating Subsidiaries in order to provide such employees with certain deferred compensation benefits. The Plan is an unfunded deferred compensation plan that is intended to qualify for the exemptions provided in Sections 201, 301, and 401 of ERISA.

2. *Definitions*

The following words and phrases shall have the following meanings unless a different meaning is plainly required by the context:

- (a) " *Basic Employer Contributions* " shall mean the amounts credited to Eligible Employees' Accounts under the Plan by the Employers, in accordance with Section 3(c).
 - (b) " *Board of Directors* " shall mean the Board of Directors of PG&E CORP, as from time to time constituted.
 - (c) " *Code* " shall mean the Internal Revenue Code of 1986, as amended. Reference to a specific section of the Code shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.
 - (d) " *Committee* " shall mean the Nominating, Compensation and Governance Committee of the Board, as it may be constituted from time to time.
 - (e) " *Eligible Employee* " shall mean an Employee who:
 - (1) Is an officer of PG&E CORP or any Participating Subsidiary and who is in Officer Band 5 or above; or
 - (2) Is a key employee of PG&E CORP or any Participating Subsidiary and who is designated by the Plan Administrator as eligible to participate in the Plan.
 - (f) " *Eligible Employee's Account* " or " *Account* " shall mean as to any Eligible Employee, the separate account maintained on the books of the Employer in accordance with Section 6(a) in order to reflect his or her interest under the Plan. Accounts shall be centrally administered by the Plan Administrator or its designee.
 - (g) " *Employee* " shall mean an individual who is treated in the records of an Employer as an employee of the Employer, who is not on an unpaid leave of absence, and/or who is not covered by a collective bargaining agreement; provided, however, such term shall not mean an individual who is a "leased employee" or who has entered into a written contract or agreement with an Employer which explicitly excludes such individual from participation in an Employer's benefit plans. The provisions of this definition shall govern, whether or not it is determined that an individual otherwise meets the definition of "common law" employee.
 - (h) " *Employers* " shall mean PG&E CORP and the Participating Subsidiaries designated by the Employee Benefit Committee of PG&E CORP. An initial list of the Employers is contained in Appendix A to this Plan.
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- (i) "ERISA" shall mean the Employee Retirement Income Security Act of 1974, as amended. Reference to a specific section of ERISA shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.
- (j) " *Investment Funds* " shall mean the investment funds established by the Board of Directors and reflected from time to time on Appendix B. The Investment Funds shall be used for tracking phantom investment results under the Plan.
- (k) " *Matching Employer Contributions* " shall mean the amounts credited to Eligible Employees' Accounts under the Plan by the Employers, in accordance with Section 3(b).
- (l) " *Participating Subsidiary* " shall mean a United States-based subsidiary of PG&E CORP, which has been designated by the Employee Benefit Committee of PG&E CORP as a Participating Subsidiary under this Plan and which has agreed to make payments or reimbursements with respect to its Eligible Employees pursuant to Section 14(d). At such times and under such conditions as the Committee may direct, one or more other subsidiaries of PG&E CORP may become Participating Subsidiaries or a Participating Subsidiary may be withdrawn from the Plan. An initial list of the Participating Subsidiaries is contained in Appendix A to this Plan.
- (m) " *PG&E CORP* " shall mean PG&E Corporation, a California corporation.
- (n) " *Plan* " shall mean the PG&E Corporation 2005 Supplemental Retirement Savings Plan, as set forth in this instrument and as heretofore and hereafter amended from time to time.
- (o) " *Plan Year* " shall mean the calendar year.
- (p) " *Prior Plan* " shall mean the PG&E Corporation Supplemental Retirement Savings Plan.
- (q) " *Retirement* " or " *Retire* " shall mean an Eligible Employee's "separation from service" within the meaning of Section 401(k) of the Code, provided that the Eligible Employee is at least 55 years of age and has been employed by an Employer for at least five years.
- (r) " *RSP* " shall mean, with respect to any Eligible Employee, the PG&E Corporation Retirement Savings Plan or any predecessor qualified retirement plan sponsored by PG&E CORP or any of its subsidiary companies.
- (s) " *Valuation Date* " shall mean:
 - (1) For purposes of valuing Plan assets and Eligible Employees' Accounts for periodic reports and statements, the date as of which such reports or statements are made; and
 - (2) For purposes of determining the amount of assets actually distributed to the Eligible Employee, his or her beneficiary, or an Alternate Payee (or available for withdrawal), a date that shall not be more than seven business days prior to the date the check is issued to the Eligible Employee.

In any other case, the Valuation Date shall be the date designated by the Plan Administrator (in its discretion) or the date otherwise set forth in this Plan. In all cases, the Plan Administrator (in its discretion) may change the Valuation Date, on a uniform and nondiscriminatory basis, as is necessary or appropriate. Notwithstanding the foregoing, the Valuation Date shall occur at least annually.

3. *Employer Contributions*

- (a) *Matching Employer Contributions* . Subject to the provisions of Section 13, the Eligible Employee's Account shall be credited for each Plan Year with a Matching Employer Contribution, calculated in the manner provided in Sections 3(a) (1), (2), and (3) below:
- (1) First, an amount shall be calculated equal to the maximum matching contribution that would be made under the terms of the RSP, taking into account for such Plan Year the amount of pre-tax deferrals and after-tax contributions the Eligible Employee elected under the RSP. For purposes of this calculation, any amounts deferred under Subsection 4(a) of this Plan shall be treated as pre-tax deferrals under the RSP.
 - (2) The calculation made in accordance with this Section 3(a) (1) above shall be made without regard to any limitation on such amounts under the RSP resulting from the application of any of the limitations under Code Sections 401(m), 401(a) (17), or 415.
 - (3) The Employer Matching Contribution to be credited to the Account of an Eligible Employee for any Plan Year shall equal the amount calculated in accordance with Sections 3(a) (1) and (2) above, reduced by the amount of matching contribution made to such Eligible Employee's account for such Plan Year under the RSP.
- (b) *Crediting of Matching Employer Contributions* . Matching Employer Contributions shall be calculated and credited to the Eligible Employee's Account as of the first business day of February of the calendar year following the Plan Year and shall be credited only if the Eligible Employee is an Employee on the last day of Plan Year for which the amounts are credited. All such amounts shall be invested in the SRSP Stable Value Fund.
- (c) *Basic Employer Contributions* . Subject to the provisions of Section 13, the Account of each Eligible Employee shall be credited for each Plan Year with a Basic Employer Contribution, calculated in the manner provided in Sections 3(c) (1), (2), and (3) below:
- (1) First, an amount shall be calculated equal to the Basic Employer Contribution that would be made under the terms of the RSP, taking into account for such Plan Year the Eligible Employee's Covered Compensation under the RSP, before any deductions for compensation deferrals elected by such Eligible Employee under Subsection 4(a) of this Plan. For Eligible Employees as defined by Section 2(e)(1) of this Plan, compensation shall also reflect such Eligible Employee's Short-Term Incentive Plan awards.
 - (2) The calculation made in accordance with this Section 3(c)(1) above shall be made without regard to any limitation on such amounts under the RSP resulting from the application of any of the limitations under Code Sections 401(a)(4), 401 (a)(17), or 415.
 - (3) The Employer Contribution to be credited to the Account of an Eligible Employee for any Plan Year shall equal the amount calculated in accordance with Sections 3(c)(1) and (2) above, reduced by the amount of Basic Employer Contributions made to such Eligible Employee's account for such Plan Year under the RSP.
- (d) *Crediting of Basic Employer Contributions* . The Employer Contribution attributable to an Eligible Employee's Short Term Incentive Plan award shall be credited to an Eligible Employee's Account as of the first business day of the month following the date on which the Short-Term Incentive Plan award is paid. All other Employer Contributions made in respect of an Eligible Employee shall be credited to the Eligible Employee's Account as of the first business day of February of the calendar year following the Plan Year and shall be credited only if the Eligible Employee is an Employee on the last day of the Plan Year for which the amounts are credited. All such amounts shall be invested in the SRSP Stable Value Fund.

- (e) *FICA Taxes* . Each Eligible Employee shall be responsible for FICA taxes on amounts credited to his or her Account under Sections 3 and 4(d).

4. *Eligible Employee Deferrals*

- (a) *Amount of Deferral* . An Eligible Employee may defer (i) 5 percent to 50 percent of his or her annual salary; and (ii) all or part of his or her Short Term Incentive Plan awards, Long-Term Incentive Plan (LTIP) awards (other than stock options), Perquisite Allowances, and any other special payments, awards, or bonuses as authorized by the Plan Administrator.
- (b) *Credits to Accounts* . Salary deferrals shall be credited to an Eligible Employee's Account as of each payroll period. All other deferrals attributable to allowances, awards, bonuses, and other payments shall be credited as of the date that they otherwise would have been paid.
- (c) *Deferral Election* . An Eligible Employee must file an election form with the Plan Administrator which indicates the percentage of salary and the amount of any awards, allowances, payments, and bonuses to be deferred under the Plan. The election shall occur according to rules established by the Plan Administrator and designed to comply with the advance election requirements under Code Section 409A. Notwithstanding the foregoing, upon first becoming an Eligible Employee, an election to defer shall be effective for the month following the filing of a Deferral Election Form, provided said Form is filed within 30 days following the date when the employee first becomes an Eligible Employee.
- (d) *Deferral of Special Incentive Stock Ownership Premiums* . All of an Eligible Employee's Special Incentive Stock Ownership Premiums are automatically deferred to the Plan immediately upon grant and converted into units in the PG&E CORP Phantom Stock Fund. The units attributable to Special Incentive Stock Ownership Premiums and any additional units resulting from the conversion of dividend equivalents thereon remain unvested until the earlier of the third anniversary of the date on which the Special Incentive Stock Ownership Premiums are credited to an Eligible Employee's account (provided the Eligible Employee continues to be employed on such date), death, disability, or retirement of the participant, or upon a Change in Control as defined in the LTIP. (The term "disability" shall, for purposes of the Plan, have the same meaning as in Section 22(e)(3) of the Internal Revenue Code.) Unvested units attributable to Special Incentive Stock Ownership Premiums and any additional units resulting from the conversion of dividend equivalents thereon shall be forfeited upon termination of the Eligible Employee's employment unless otherwise provided in the PG&E Corporation Executive Stock Ownership Program or if an Eligible Employee's stock ownership falls below the levels set forth in the Executive Stock Ownership Program.

5. *Investment Funds*

Although no assets will be segregated or otherwise set aside with respect to an Eligible Employee's Account, the amount that is ultimately payable to the Eligible Employee with respect to such Account shall be determined as if such Account had been invested in some or all of the Investment Funds. The Plan Administrator, in its sole discretion, shall adopt (and modify from time to time) such rules and procedures as it deems necessary or appropriate to implement the deemed investment of the Eligible Employees' Accounts. Such procedures generally shall provide that an Eligible Employee's Account shall be deemed to be invested among the available Investment Funds in the manner elected by the Eligible Employee in such percentages and manner as prescribed by the Plan Administrator. In the event no election has been made by the Eligible Employee, such Account will be deemed to be invested in the SRSP Stable Value Fund. Eligible Employees shall be able to reallocate their Accounts between the Investment Funds and reallocate amounts newly credited to their Accounts at such time and in such manner as the Plan Administrator shall prescribe. Anything to the contrary herein notwithstanding, an Eligible

Employee may not reallocate Account balances between Investment Funds if such reallocation would result in a non-exempt Discretionary Transaction as defined in Rule 16b-3 of the Securities Exchange Act of 1934, as amended, or any successor to Rule 16b-3, as in effect when the reallocation is requested. The available Investment Funds shall be listed on Appendix B and may be changed from time to time by the Board of Directors.

6. *Accounting*

- (a) *Eligible Employees' Accounts* . At the direction of the Plan Administrator, there shall be established and maintained on the books of the Employer, a separate account for each Eligible Employee in order to reflect his or her interest under the Plan.
- (b) *Investment Earnings* . Each Eligible Employee's Account shall initially reflect the value of his or her Account's interest in each of the Investment Funds, deemed acquired with the amounts credited thereto. Each Eligible Employee's Account shall also be credited (or debited) with the net appreciation (or depreciation), earnings and gains (or losses) with respect to the investments deemed made by his or her Account. Any such net earnings or gains deemed realized with respect to any investment of any Eligible Employee's Account shall be deemed reinvested in additional amounts of the same investment and credited to the Eligible Employee's Account.
- (c) *Accounting Methods* . The accounting methods or formulae to be used under the Plan for the purpose of maintaining the Eligible Employees' Accounts shall be determined by the Plan Administrator. The accounting methods or formulae selected by the Plan Administrator may be revised from time to time but shall conform to the extent practicable with the accounting methods used under the Applicable Plan.
- (d) *Valuations and Reports* . The fair market value of each Eligible Employee's Account shall be determined as of each Valuation Date. In making such determinations and in crediting net deemed earnings and gains (or losses) in the Investment Funds to the Eligible Employees' Accounts, the Plan Administrator (in its discretion) may employ such accounting methods as the Plan Administrator (in its discretion) may deem appropriate in order to fairly reflect the fair market values of the Investment Funds and each Eligible Employee's Account. For this purpose, the Plan Administrator may rely upon information provided by the Plan Administrator or other persons believed by the Plan Administrator to be competent.
- (e) *Statements of Eligible Employee's Accounts* . Each Eligible Employee shall be furnished with periodic statements of his or her interest in the Plan.

7. *Distributions*

- (a) *Distribution of Account Balances* . Except to the extent the Eligible Employee has elected otherwise under this Section 7 at the time of a deferral election, distribution of the balance credited to an Eligible Employee's Account shall be made in a single lump sum as soon as reasonably practicable seven (7) months following Retirement or termination of service.

In the case of an Alternate Payee (as defined in Section 9(a)), to the extent allowable under Code Section 409A, distribution shall be made as directed in a domestic relations order which the Plan Administrator determines is a QDRO (as defined in Section 9(a)), but only as to the portion of the Eligible Employee's Account which the QDRO states is payable to the Alternate Payee.

- (b) *" Specific Date " Distributions* . By filing an irrevocable election with the Plan Administrator, an Eligible Employee may at the time of deferral elect to commence distribution of the specific type of income deferral for that calendar year plus the earnings thereon (exclusive of Special Incentive Stock Ownership Premiums) in January of any future year.

- (c) *Change in Distribution Election* . An Eligible Employee may change a distribution election previously made pursuant to Section 7(b) (or in place by default pursuant to Section 7(a)) only with respect to the portion of the Eligible Employee's Account attributable to Eligible Employee Deferrals (exclusive of Special Incentive Stock Ownership Premiums) and only in accordance with the rules under Code Section 409A. Generally, a subsequent election pursuant to this Section 7(c): (1) cannot take effect for twelve (12) months, (2) must occur at least twelve (12) months before the first scheduled payment under a payment at a specified date elected pursuant to Section 7(b), and (3) must defer a previously elected distribution at least five (5) additional years. The Plan Administrator may establish additional rules or restrictions on changes in distribution elections.
- (d) *Death Distributions* . If an Eligible Employee dies before the entire balance of his or her Account has been distributed (whether or not the Eligible Employee had previously terminated employment and whether or not installment payments had previously commenced), the remaining balance of the Eligible Employee's Account shall be distributed to the beneficiary designated or otherwise determined in accordance with Section 7(g), as soon as practicable after the date of death.
- (e) *Special Incentive Stock Ownership Premiums* . Distributions attributable to Special Incentive Stock Ownership Premiums shall only be made as soon as reasonably practicable (7) months after an Eligible Employee terminates employment, Retires, or dies, and shall only be made in the form of one or more certificates for the number of vested Special Incentive Stock Ownership Premium units, rounded down to the nearest whole share.
- (f) *Effect of Change in Eligible Employee Status* . If an Eligible Employee ceases to be an Eligible Employee, the balance credited to his or her Account shall continue to be credited (or debited) with appreciation, depreciation, earnings, gains or losses under the terms of the Plan and shall be distributed to him or her at the time and in the manner set forth in this Section 7; provided, however, that if an Eligible Employee terminates employment with an Employer other than by reason of Retirement, the entire balance credited to his or her Account shall be distributed in a lump sum cash payment as soon as reasonably practicable seven (7) months following termination of employment.
- (g) *Payments to Incompetents* . If any individual to whom a benefit is payable under the Plan is a minor or if the Plan Administrator determines that any individual to whom a benefit is payable under the Plan is incompetent to receive such payment or to give a valid release therefor, payment shall be made to the guardian, committee, or other representative of the estate of such individual which has been duly appointed by a court of competent jurisdiction. If no guardian, committee, or other representative has been appointed, payment may be made to any person as custodian for such individual under the California Uniform Transfers to Minors Act (or similar law of another state) or may be made to or applied to or for the benefit of the minor or incompetent, the incompetent's spouse, children or other dependents, the institution or persons maintaining the minor or incompetent, or any of them, in such proportions as the Plan Administrator from time to time shall determine; and the release of the person or institution receiving the payment shall be a valid and complete discharge of any liability of PG&E CORP with respect to any benefit so paid.
- (h) *Beneficiary Designations* . Each Eligible Employee may designate, in a signed writing delivered to the Plan Administrator, on such form as it may prescribe, one or more beneficiaries to receive any distribution which may become payable under the Plan as the result of the Eligible Employee's death. An Eligible Employee may designate different beneficiaries at any time by delivering a new designation in like manner. Any designation shall become effective only upon its receipt by the Plan Administrator, and the last effective designation received by the Plan

Administrator shall supersede all prior designations. If an Eligible Employee dies without having designated a beneficiary or if no beneficiary survives the Eligible Employee, the Eligible Employee's Account shall be payable to the beneficiary or beneficiaries designated or otherwise determined under the RSP.

- (i) *Undistributable Accounts* . Each Eligible Employee and (in the event of death) his or her beneficiary shall keep the Plan Administrator advised of his or her current address. If the Plan Administrator is unable to locate the Eligible Employee or beneficiary to whom an Eligible Employee's Account is payable under this Section 7, the Eligible Employee's Account shall be frozen as of the date on which distribution would have been completed in accordance with this Section 7, and no further appreciation, depreciation, earnings, gains or losses shall be credited (or debited) thereto. PG&E CORP shall have the right to assign or transfer the liability for payment of any undistributable Account to the Eligible Employee's former Employer (or any successor thereto).
- (j) *Plan Administrator Discretion* . Within the specific time periods described in this Section 7, the Plan Administrator shall have sole discretion to determine the specific timing of the payment of any Account balance under the Plan.

8. *Distribution Due to Unforeseeable Emergency (Hardship Distribution)*

A participant may request a distribution due to an unforeseeable emergency (within the meaning of Code Section 409A) by submitting a written request to the Plan Administrator. The Plan Administrator shall have the authority to require such evidence as it deems necessary to determine if a distribution is warranted. If an application for a hardship distribution due to an unforeseeable emergency is approved, the distribution shall be payable in a method determined by the Plan Administrator as soon as possible after approval of such distribution. After receipt of a payment requested due to an unforeseeable emergency, a participant may not make additional deferrals during the remainder of the Plan Year in which the recipient received the payment. A participant who has commenced receiving installment payments under the Plan may request acceleration of such payments in the event of an unforeseeable emergency. The Administrator may permit accelerated payments to the extent such accelerated payment does not exceed the amount necessary to meet the emergency.

9. *Domestic Relations Orders*

- (a) *Qualified Domestic Relations Orders* . The Plan Administrator shall establish written procedures for determining whether a domestic relations order purporting to dispose of any portion of an Eligible Employee's Account is a qualified domestic relations order (within the meaning of Section 414(p) of the Code) (a " QDRO ").
 - (1) *No Payment Unless a QDRO*. No payment shall be made to any person designated in a domestic relations order (an " *Alternate Payee* ") until the Plan Administrator (or a court of competent jurisdiction reversing an initial adverse determination by the Plan Administrator) determines that the order is a QDRO. Payment shall be made to each Alternate Payee as specified in the QDRO.
 - (2) *Time of Payment* . Payment may be made to an Alternate Payee in the form of a lump sum, at the time specified in the QDRO, but no earlier than as soon as practicable following the date the QDRO determination is made.
 - (3) *Hold Procedures* . Notwithstanding any contrary Plan provision, prior to the receipt of a domestic relations order, the Plan Administrator may, in its sole discretion, place a hold upon all or a portion of an Eligible Employee's Account for a reasonable period of time (as determined by the Plan Administrator) if the Plan Administrator receives notice that

(a) a domestic relations order is being sought by the Eligible Employee, his or her spouse, former spouse, child or other dependent, and (b) the Eligible Employee's Account is a source of the payment under such domestic relations order. For purposes of this Section 9(a)(3), a "hold" means that no withdrawals, distributions, or investment transfers may be made with respect to an Eligible Employee's Account. If the Plan Administrator places a hold upon an Eligible Employee's Account pursuant to this Section 9(a)(3), it shall inform the Eligible Employee of such fact.

10. *Vesting*

Except as provided in Section 4(d), an Eligible Employee's interest in his or her Account at all times shall be 100 percent vested and nonforfeitable.

11. *Administration of the Plan*

- (a) *Plan Administrator* . The Employee Benefit Committee of PG&E CORP is hereby designated as the administrator of the Plan (within the meaning of Section 3(16)(A) of ERISA). The Plan Administrator delegates to the Senior Human Resource Officer for PG&E CORP, or his or her designee, the authority to carry out all duties and responsibilities of the Plan Administrator under the Plan. The Plan Administrator shall have the authority to control and manage the operation and administration of the Plan.
- (b) *Powers of Plan Administrator* . The Plan Administrator shall have all discretion and powers necessary to supervise the administration of the Plan and to control its operation in accordance with its terms, including, but not by way of limitation, the power to interpret the provisions of the Plan and to determine, in its sole discretion, any question arising under, or in connection with the administration or operation of, the Plan.
- (c) *Decisions of Plan Administrator* . All decisions of the Plan Administrator and any action taken by it in respect of the Plan and within the powers granted to it under the Plan shall be conclusive and binding on all persons and shall be given the maximum deference permitted by law.

12. *Funding*

All amounts credited to an Eligible Employee's Account under the Plan shall continue for all purposes to be a part of the general assets of PG&E CORP. The interest of the Eligible Employee in his or her Account, including his or her right to distribution thereof, shall be an unsecured claim against the general assets of PG&E CORP. While PG&E CORP may choose to invest a portion of its general assets in investments identical or similar to those selected by Eligible Employees for purposes of determining the amounts to be credited (or debited) to their Accounts, nothing contained in the Plan shall give any Eligible Employee or beneficiary any interest in or claim against any specific assets of PG&E CORP.

13. *Modification or Termination of Plan*

- (a) *Employers' Obligations Limited* . The Plan is voluntary on the part of the Employers, and the Employers do not guarantee to continue the Plan. PG&E CORP at any time may, by appropriate amendment of the Plan, suspend Matching Employer Contributions and/or Basic Employer Contributions or may discontinue Matching Employer Contributions and/or Basic Employer Contributions, with or without cause.
- (b) *Right to Amend or Terminate* . The Board of Directors, acting through its Nominating and Compensation Committee, reserves the right to alter, amend, or terminate the Plan, or any part thereof, in such manner as it may determine, for any reason whatsoever.

(1) *Limitations* . Any alteration, amendment, or termination shall take effect upon the date indicated in the document embodying such alteration, amendment, or termination, provided that no such alteration or amendment shall divest any portion of an Account that is then vested under the Plan.

(c) *Effect of Termination* . If the Plan is terminated, the balances credited to the Accounts of the Eligible Employees affected by such termination shall be distributed to them at the time and in the manner set forth in Section 7; provided, however, that the Plan Administrator, in its sole discretion, may authorize accelerated distribution of Eligible Employees' Accounts as of any earlier date.

14. *General Provisions*

(a) *Inalienability* . Except to the extent otherwise directed by a domestic relations order which the Plan Administrator determines is a QDRO (as defined in Section 9(a) or mandated by applicable law, in no event may either an Eligible Employee, a former Eligible Employee or his or her spouse, beneficiary or estate sell, transfer, anticipate, assign, hypothecate, or otherwise dispose of any right or interest under the Plan; and such rights and interests shall not at any time be subject to the claims of creditors nor be liable to attachment, execution, or other legal process.

(b) *Rights and Duties* . Neither the Employers nor the Plan Administrator shall be subject to any liability or duty under the Plan except as expressly provided in the Plan, or for any action taken, omitted, or suffered in good faith.

(c) *No Enlargement of Employment Rights* . Neither the establishment or maintenance of the Plan, the making of any Matching Employer Contributions, nor any action of any Employer or Plan Administrator, shall be held or construed to confer upon any individual any right to be continued as an Employee nor, upon dismissal, any right or interest in any specific assets of the Employers other than as provided in the Plan. Each Employer expressly reserves the right to discharge any Employee at any time, with or without cause or advance notice.

(d) *Apportionment of Costs and Duties* . All acts required of the Employers under the Plan may be performed by PG&E CORP for itself and its Participating Subsidiaries, and the costs of the Plan may be equitably apportioned by the Plan Administrator among PG&E CORP and the other Employers. Whenever an Employer is permitted or required under the terms of the Plan to do or perform any act, matter or thing, it shall be done and performed by any officer or employee of the Employer who is thereunto duly authorized by the board of directors of the Employer. Each Participating Subsidiary shall be responsible for making benefit payments pursuant to the Plan on behalf of its Eligible Employees or for reimbursing PG&E CORP for the cost of such payments, as determined by PG&E CORP in its sole discretion. In the event the respective Participating Subsidiary fails to make such payment or reimbursement, and PG&E CORP does not exercise its discretion to make the payment on such Participating Subsidiary's behalf, participation in the Plan by the Eligible Employees of that Participating Subsidiary shall be suspended. If at some future date, the Participating Subsidiary makes all past-due payments and reimbursements, plus interest at a rate determined by PG&E CORP in its sole discretion, the suspended participation of its Eligible Employees eligible to participate in the Plan will be recognized. In the event the respective Participating Subsidiary fails to make such payment or reimbursement, an Eligible Employee's (or other payee's) sole recourse shall be against the respective Participating Subsidiary, and not against PG&E CORP. An Eligible Employee's participation in the Plan shall constitute agreement with this provision.

(e) *Applicable Law* . The provisions of the Plan shall be construed, administered, and enforced in accordance with the laws of the State of California and, to the extent applicable, ERISA.

(f) *Severability* . If any provision of the Plan is held invalid or unenforceable, its invalidity or unenforceability shall not affect any other provisions of the Plan, and the Plan shall be construed and enforced as if such provision had not been included.

(g) *Captions* . The captions contained in and the table of contents prefixed to the Plan are inserted only as a matter of convenience and for reference and in no way define, limit, enlarge, or describe the scope or intent of the Plan nor in any way shall affect the construction of any provision of the Plan.

APPENDIX A

EMPLOYERS (As of January 1, 2005)

—PG&E Corporation

—All Participating Subsidiaries

Participating Subsidiaries (as of January 1, 2005):

—Pacific Gas and Electric Company

—All U.S. subsidiaries of the above-named corporations

APPENDIX B

INVESTMENT FUNDS (as of January 1, 2005)

Participating Investment Funds as of January 1, 2005

1. **AA Utility Bond Fund** accrues interest on the amount invested in this fund. The interest rate is equal to the AA Utility Bond Yield reported by Moody's Investor Services.
2. **PG&E Corporation Phantom Stock Fund** converts contributions and transferred amounts into units of phantom common stock valued at the closing price of a share of PG&E Corporation common stock on the contribution/transfer date. If the transfer request is received after the market closes, the following day's closing price will be used. Thereafter, the value of a unit shall fluctuate depending on the price of PG&E Corporation common stock. Each time a dividend is paid on common stock, an amount equal to such dividend shall be credited to the account as additional units.
3. **SRSP Large Company Stock Index Fund** seeks to match the performance of the S&P 500 Index. The Fund invests in all 500 stocks in the S&P 500 Index in proportion to their weightings in the Index. The S&P 500 provides exposure to about 85% of the market value of all publicly traded common stocks in the United States. The strategy of investing in the same stocks as the S&P 500 Index minimizes the need for trading and results in lower expenses. The Fund is managed by State Street Global Advisors (SSgA).
4. **SRSP International Stock Index Fund** seeks to match closely the performance of the MSCI EAFE Index. The Fund invests in all of the stocks in the MSCI EAFE Index in proportion to their weightings in the Index. The strategy of investing in the same stocks as the MSCI EAFE minimizes the need for trading and results in lower expenses. The Fund is managed by State Street Global Advisors (SSgA).
5. **SRSP Conservative Asset Allocation Fund** is a pre-mixed portfolio of commingled stock and bond funds. The Fund will invest approximately 60% in Fixed Income Securities, 30% in U.S. Large Cap Equities, 5% in U.S. Small Cap Equities, and 5% in International Equities. The underlying funds are managed by State Street Global Advisors (SSgA). These funds are combined and rebalanced daily by Fidelity Management Trust Company on direction from PG&E Corporation.
6. **SRSP Moderate Asset Allocation Fund** is a pre-mixed portfolio of commingled stock and bond funds. The Fund will invest approximately 40% in Fixed Income Securities, 42% in U.S. Large Cap Equities, 8% in U.S. Small Cap Equities, and 10% in International Equities. The underlying funds are managed by State Street Global Advisors (SSgA). These funds are combined and rebalanced daily by Fidelity Management Trust Company on direction from PG&E Corporation.
7. **SRSP Aggressive Asset Allocation Fund** is a pre-mixed portfolio of commingled stock and bond funds. The Fund will invest approximately 55% in U.S. Large Cap Equities, 20% in Fixed Income Securities, 10% in U.S. Small Cap Equities, and 15% in International Equities. The underlying funds are managed by State Street Global Advisors (SSgA). These funds are combined and rebalanced daily by Fidelity Management Trust Company on direction from PG&E Corporation.
8. **SRSP Stable Value Fund** seeks to provide safety of principal and liquidity while providing a higher return over time than that offered by money market funds. The Fund invests in diversified portfolio investment contracts issued by insurance companies, banks, and other financial institutions. An investment contract is an agreement where the issuer promises to pay a specific rate of return to the holder for a period of time. The quality of the promise depends on the

financial strength of the issuer. The Fund may also hold a small percentage of cash or other short-term investments. The Fund is managed by PRIMCO Capital Management.

9. **SRSP Bond Index Fund** seeks to match the returns of the Lehman Brothers Aggregate Bond Index. The Fund invests primarily in government, corporate, mortgage-backed, and asset-backed fixed-income securities. The Fund invests in a well-diversified portfolio that is representative of the broad domestic bond market. The Lehman Brothers Aggregate Bond Index is an unmanaged market-value weighted index of investment-grade, fixed-rate debt issues, including government, corporate, asset-backed, and mortgage-backed securities, with maturities of one year or more. The Fund is managed by State Street Global Advisors (SSgA).
10. **SRSP Small Company Stock Index Fund** seeks to match the performance of the Russell Small Cap Completeness Index. The Fund invests in all of the stocks in the Russell Special Small Cap Completeness Index in proportion to their weightings in the Index. These stocks represent about 15% of the market value of all publicly traded common stocks in the United States. The strategy of investing in the same stocks as the Russell Small Cap Completeness Index minimizes the need for trading and results in lower expenses. The Fund is managed by State Street Global Advisors (SSgA).

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Exhibit 10.17

PG&E CORPORATION
2005 DEFERRED COMPENSATION PLAN FOR NON-EMPLOYEE DIRECTORS

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PG&E CORPORATION
2005 DEFERRED COMPENSATION PLAN FOR NON-EMPLOYEE DIRECTORS

This is the controlling and definitive statement of the PG&E CORPORATION ("PG&E CORP") 2005 Deferred Compensation Plan for Non-Employee Directors (the "Plan"). Except as provided herein, the Plan is effective as of January 1, 2005, with respect to all individuals who are Directors as of such date. The Plan continues the program embodied in the PG&E Corporation Deferred Compensation Plan for Non-Employee Directors (the "Prior Plan").

1. *Purpose of the Plan*

The Plan is established and is maintained for the benefit of Directors of PG&E CORP in order to provide the Directors with an opportunity to defer receipt of their Meeting Fees and Retainer Fees. The Plan is an unfunded deferred compensation plan.

2. *Definitions*

The following words and phrases shall have the following meanings unless a different meaning is plainly required by the context:

- (a) " *Board of Directors* " shall mean the Board of Directors of PG&E CORP, as from time to time constituted.
 - (b) " *Code* " shall mean the Internal Revenue Code of 1986, as amended. Reference to a specific section of the Code shall include such section, any valid regulation promulgated thereunder, and any comparable provision of any future legislation amending, supplementing, or superseding such section.
 - (c) " *Committee* " shall mean the Nominating, Compensation and Governance Committee of the Board of Directors, as it may be constituted from time to time.
 - (d) " *Deferred Compensation Account* " or " *Account* " shall mean as to any Director, the separate account maintained on the books of PG&E CORP in accordance with Section 6(a) in order to reflect his or her interest under the Plan. Accounts shall be centrally administered by the Plan Administrator or its designee.
 - (e) " *Director* " shall mean any member of the Board of Directors who is not an employee of PG&E CORP or a Subsidiary.
 - (f) " *Director's Termination Date* " shall mean the effective date of the Director's resignation from the Board of Directors of the Corporation.
 - (g) " *Investment Funds* " shall mean the investment funds established by the Board of Directors and reflected from time to time on Appendix A. The Investment Funds shall be used for tracking phantom investment results under the Plan.
 - (h) " *Meeting Fee* " means the amount of compensation paid by PG&E CORP to a Director for his or her attendance and services at a meeting of the Board of Directors or any committee thereof. A Meeting Fee shall not include (i) any Retainer Fee, or (ii) any reimbursement by PG&E CORP of expenses incurred by a Director incidental to attendance at a meeting of the Board of Directors or of a committee thereof or of any other expense incurred on behalf of PG&E CORP.
 - (i) " *PG&E CORP* " shall mean PG&E Corporation, a California corporation.
 - (j) " *Plan* " shall mean the PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, as set forth in this instrument and as amended from time to time.
 - (k) " *Plan Year* " shall mean the calendar year.
 - (l) " *Prior Plan* " shall mean the PG&E Corporation Deferred Compensation Plan for Non-Employee Directors.
-

- (m) " *Retainer Fee* " means the amount of compensation paid by PG&E CORP to a Director for retaining his or her services during a calendar quarter. A Retainer Fee shall not include (i) any Meeting Fee, or (ii) any reimbursement by PG&E CORP of expenses incurred by a Director incidental to attendance at a meeting of the Board of Directors or of a committee thereof or of any other expense incurred on behalf of PG&E CORP.
- (n) " *Subsidiary* " shall mean a subsidiary of PG&E CORP.
- (o) " *Valuation Date* " shall mean:
 - (1) For purposes of valuing Plan assets and Directors' Accounts for periodic reports and statements, the date as of which such reports or statements are made; and
 - (2) For purposes of determining the amount of assets actually distributed to the Director or his or her beneficiary (or available for withdrawal), a date that shall not be more than seven business days prior to the date the check is issued to the Director.

In any other case, the Valuation Date shall be the date designated by the Plan Administrator (in its discretion) or the date otherwise set forth in this Plan. In all cases, the Plan Administrator (in its discretion) may change the Valuation Date, on a uniform and nondiscriminatory basis, as is necessary or appropriate. Notwithstanding the foregoing, the Valuation Date shall occur at least annually.

3. *Eligibility*

Each Director who receives a Meeting Fee or Retainer Fee for service on the Board of Directors shall be eligible to participate in the Plan.

4. *Deferrals*

- (a) *Amount of Deferral* . A participating Director may defer (i) all Retainer Fees only; (ii) Meeting Fees only; or (iii) all Retainer Fees and all Meeting Fees.
- (b) *Credits to Accounts* . Deferrals shall be credited to a Director's Account as of the date that they otherwise would have been paid.
- (c) *Deferral Election* . A Director must file an election form with the Corporate Secretary which indicates whether Retainer Fees, Meeting Fees or both are to be deferred under the Plan. The election shall occur according to rules established by the Plan Administrator and designed to comply with the advance election requirements under Code Section 409A. Notwithstanding the foregoing, upon first becoming a Director, an election to defer shall be effective for Meeting Fees and/or Retainer Fees earned following the filing of a Deferral Election Form, provided said Form is filed with the Corporate Secretary within 30 days following the date when the individual first becomes a Director.

5. *Investment Funds*

Although no assets will be segregated or otherwise set aside with respect to a Director's Account, the amount that is ultimately payable to the Director with respect to such Account shall be determined as if such Account had been invested in some or all of the Investment Funds. The Plan Administrator, in its sole discretion, shall adopt (and modify from time to time) such rules and procedures as it deems necessary or appropriate to implement the deemed investment of the Directors' Accounts. Such procedures generally shall provide that a Director's Account shall be deemed to be invested among the available Investment Funds in the manner elected by the Director in such percentages and manner as prescribed by the Plan Administrator. In the event no election has been made by the Director, such Account will be deemed to be invested in the AA Utility Bond Fund. Directors shall be able to reallocate their Accounts between the Investment Funds and reallocate amounts newly credited to their Accounts at such time and in such manner as the Plan Administrator shall prescribe. Anything to the contrary herein notwithstanding, a Director may not reallocate Account balances between Investment Funds if such reallocation

would result in a non-exempt Discretionary Transaction as defined in Rule 16b-3 of the Securities Exchange Act of 1934, as amended, or any successor to Rule 16b-3, as in effect when the reallocation is requested. The available Investment Funds shall be listed on Appendix A and may be changed from time to time by the Board of Directors.

6. *Accounting*

- (a) *Accounts* . At the direction of the Plan Administrator, there shall be established and maintained on the books of PG&E CORP, a separate account for each participating Director in order to reflect his or her interest under the Plan.
- (b) *Investment Earnings* . Each Director's Account shall initially reflect the value of his or her Account's interest in each of the Investment Funds, deemed acquired with the amounts credited thereto. Each Director's Account shall also be credited (or debited) with the net appreciation (or depreciation), earnings and gains (or losses) with respect to the investments deemed made by his or her Account. Any such net earnings or gains deemed realized with respect to any investment of any Director's Account shall be deemed reinvested in additional amounts of the same investment and credited to the Director's Account.
- (c) *Accounting Methods* . The accounting methods or formulae to be used under the Plan for the purpose of maintaining the Directors' Accounts shall be determined by the Plan Administrator. The accounting methods or formulae selected by the Plan Administrator may be revised from time to time but shall conform to the extent practicable with the accounting methods used under the Applicable Plan.
- (d) *Valuations and Reports* . The fair market value of each Director's Account shall be determined as of each Valuation Date. In making such determinations and in crediting net deemed earnings and gains (or losses) in the Investment Funds to the Directors' Accounts, the Plan Administrator (in its discretion) may employ such accounting methods as the Plan Administrator (in its discretion) may deem appropriate in order to fairly reflect the fair market values of the Investment Funds and each Director's Account. For this purpose, the Plan Administrator may rely upon information provided by the Plan Administrator or other persons believed by the Plan Administrator to be competent.
- (e) *Statements of Director's Accounts* . Each Director shall be furnished with periodic statements of his or her interest in the Plan by January 31 of each year.

7. *Distributions*

- (a) *Distribution of Account Balances* . Except to the extent the Director has elected otherwise under this Section 7 at the time of a deferral election, distribution of the balance credited to a Director's Account shall be made in a single lump sum in January of the year following the Director's Termination Date.
- (b) *Installment Distributions* . In lieu of a single sum payment, a Director may at the time of deferral elect in writing and file with the Plan Administrator an election that payment of amounts credited to the Director's Account be made in 10 approximately equal annual installments. However, if during the installment payment period the Account balance is less than \$5,000, the value of the remaining installments shall be paid as a lump sum. Installment payments (including a final payment pursuant to the preceding sentence) will be made in January of the year following the Director's Termination Date and on each anniversary thereof until all installments are paid.
- (c) *"Specific Date" Distributions* . By filing an irrevocable election with the Plan Administrator, a Director may at the time of deferral elect to commence distribution of full or partial payment of the balance of his or her Account in January of any future year.

- (d) *Change in Distribution Election* . A Director may change a distribution election previously made pursuant to Section 7(b) or Section 7(c) only in accordance with the rules under Code Section 409A. Generally, a subsequent election pursuant to this Section 7(d): (1) cannot take effect for twelve (12) months, (2) must occur at least twelve (12) months before the first scheduled payment under a payment at a specified date elected pursuant to Section 7(c), and (3) must defer a previously elected distribution at least five (5) additional years. The Plan Administrator may establish additional rules or restrictions on changes in distribution elections.
- (e) *Death Distributions* . If a Director dies before the entire balance of his or her Account has been distributed (whether or not the Director's Board service had previously terminated and whether or not installment payments had previously commenced), the remaining balance of the Director's Account shall be distributed to the beneficiary designated or otherwise determined in accordance with Section 7(g), as soon as practicable after the date of death.
- (f) *Payments to Incompetents* . If any individual to whom a benefit is payable under the Plan is a minor or if the Plan Administrator determines that any individual to whom a benefit is payable under the Plan is incompetent to receive such payment or to give a valid release therefor, payment shall be made to the guardian, committee, or other representative of the estate of such individual which has been duly appointed by a court of competent jurisdiction. If no guardian, committee, or other representative has been appointed, payment may be made to any person as custodian for such individual under the California Uniform Transfers to Minors Act (or similar law of another state) or may be made to or applied to or for the benefit of the minor or incompetent, the incompetent's spouse, children or other dependents, the institution or persons maintaining the minor or incompetent, or any of them, in such proportions as the Plan Administrator from time to time shall determine; and the release of the person or institution receiving the payment shall be a valid and complete discharge of any liability of PG&E CORP with respect to any benefit so paid.
- (g) *Beneficiary Designations* . Each Director may designate, in a signed writing delivered to the Plan Administrator, on such form as it may prescribe, one or more beneficiaries to receive any distribution which may become payable under the Plan as the result of the Director's death. A Director may designate different beneficiaries at any time by delivering a new designation in like manner. Any designation shall become effective only upon its receipt by the Plan Administrator, and the last effective designation received by the Plan Administrator shall supersede all prior designations. If a Director dies without having designated a beneficiary or if no beneficiary survives the Director, the Director's Account shall be payable to the estate or the last to die of the Director.
- (h) *Undistributable Accounts* . Each Director and (in the event of death) his or her beneficiary shall keep the Plan Administrator advised of his or her current address. If the Plan Administrator is unable to locate the Director or beneficiary to whom a Director's Account is payable under this Section 7, the Director's Account shall be frozen as of the date on which distribution would have been completed in accordance with this Section 7, and no further appreciation, depreciation, earnings, gains or losses shall be credited (or debited) thereto.
- (i) *Plan Administrator Discretion* . Within the specific time periods described in this Section 7, the Plan Administrator shall have sole discretion to determine the specific timing of the payment of any Account balance under the Plan.

8. *Distribution Due to Unforeseeable Emergency (Hardship Distribution)*

A participant may request a distribution due to an unforeseeable emergency (within the meaning of Code Section 409A) by submitting a written request to the Plan Administrator. The Plan Administrator shall have the authority to require such evidence as it deems necessary to determine

if a distribution is warranted. If an application for a hardship distribution due to an unforeseeable emergency is approved, the distribution shall be payable in a method determined by the Plan Administrator as soon as possible after approval of such distribution. After receipt of a payment requested due to an unforeseeable emergency, a participant may not make additional deferrals during the remainder of the Plan Year in which the recipient received the payment. A participant who has commenced receiving installment payments under the Plan may request acceleration of such payments in the event of an unforeseeable emergency. The Administrator may permit accelerated payments to the extent such accelerated payment does not exceed the amount necessary to meet the emergency.

9. *Vesting*

A Director's interest in his or her Account at all times shall be 100 percent vested and nonforfeitable.

10. *Administration of the Plan*

- (a) *Plan Administrator* . The Committee is hereby designated as the administrator of the Plan. The Plan Administrator delegates to the Corporate Secretary, or his or her designee, the authority to carry out all duties and responsibilities of the Plan Administrator under the Plan. The Plan Administrator shall have the authority to control and manage the operation and administration of the Plan.
- (b) *Powers of Plan Administrator* . The Plan Administrator shall have all discretion and powers necessary to supervise the administration of the Plan and to control its operation in accordance with its terms, including, but not by way of limitation, the power to interpret the provisions of the Plan and to determine, in its sole discretion, any question arising under, or in connection with the administration or operation of, the Plan.
- (c) *Decisions of Plan Administrator* . All decisions of the Plan Administrator and any action taken by it in respect of the Plan and within the powers granted to it under the Plan shall be conclusive and binding on all persons and shall be given the maximum deference permitted by law.

11. *Funding*

All amounts credited to a Director's Account under the Plan shall continue for all purposes to be a part of the general assets of PG&E CORP. The interest of the Director in his or her Account, including his or her right to distribution thereof, shall be an unsecured claim against the general assets of PG&E CORP. While PG&E CORP may choose to invest a portion of its general assets in investments identical or similar to those selected by Directors for purposes of determining the amounts to be credited (or debited) to their Accounts, nothing contained in the Plan shall give any Director or beneficiary any interest in or claim against any specific assets of PG&E CORP.

12. *Modification or Termination of Plan*

- (a) *Obligations Limited* . The Plan is voluntary on the part of PG&E CORP, and PG&E CORP does not guarantee to continue the Plan.
- (b) *Right to Amend or Terminate* . The Board of Directors, acting through its Nominating, Compensation and Governance Committee, reserves the right to alter, amend, or terminate the Plan, or any part thereof, in such manner as it may determine, for any reason whatsoever.
 - (1) *Limitations* . Any alteration, amendment, or termination shall take effect upon the date indicated in the document embodying such alteration, amendment, or termination, provided that no such alteration or amendment shall divest any portion of an Account that is then vested under the Plan.

- (c) *Effect of Termination* . If the Plan is terminated, the balances credited to the Accounts of the Directors affected by such termination shall be distributed to them at the time and in the manner set forth in Section 7; provided, however, that the Plan Administrator, in its sole discretion, may authorize accelerated distribution of Directors' Accounts as of any earlier date.

13. *General Provisions*

- (a) *Inalienability* . Except to the extent mandated by applicable law, in no event may either a Director, a former Director or his or her spouse, beneficiary or estate sell, transfer, anticipate, assign, hypothecate, or otherwise dispose of any right or interest under the Plan; and such rights and interests shall not at any time be subject to the claims of creditors nor be liable to attachment, execution, or other legal process.
- (b) *Rights and Duties* . Neither PG&E CORP nor the Plan Administrator shall be subject to any liability or duty under the Plan except as expressly provided in the Plan, or for any action taken, omitted, or suffered in good faith.
- (c) *No Enlargement of Rights* . Neither the establishment or maintenance of the Plan, nor any action of PG&E CORP or Plan Administrator, shall be held or construed to confer upon any individual any right to be continued as a Director nor, upon dismissal, any right or interest in any specific assets of PG&E CORP other than as provided in the Plan. PG&E CORP expressly reserves the right to remove any Director at any time, with or without cause or advance notice.
- (d) *Applicable Law* . The provisions of the Plan shall be construed, administered, and enforced in accordance with the laws of the State of California.
- (e) *Severability* . If any provision of the Plan is held invalid or unenforceable, its invalidity or unenforceability shall not affect any other provisions of the Plan, and the Plan shall be construed and enforced as if such provision had not been included.
- (f) *Captions* . The captions contained in and the table of contents prefixed to the Plan are inserted only as a matter of convenience and for reference and in no way define, limit, enlarge, or describe the scope or intent of the Plan nor in any way shall affect the construction of any provision of the Plan.

APPENDIX A

INVESTMENT FUNDS (as of January 1, 2005)

Participating Investment Funds as of January 1, 2005

- (1) AA Utility Bond Fund. Interest shall be credited daily on the amounts invested in the AA Utility Bond Fund. Such interest shall be at a rate equal to the AA Utility Bond Yield reported by *Moody's Investors Service*. Such interest shall become a part of the Director's Account and shall be paid at the same time or times as the balance of the Director's Account.
- (2) PG&E CORP Phantom Stock Fund. Amounts credited to the PG&E CORP Phantom Stock Fund shall be converted into units (including fractions computed to three decimal places) each representing a share of PG&E CORP common stock. The value of a unit for purposes of determining the number of units to credit upon initial allocation or upon reallocation from another Investment Fund, and for determining the dollar value of the aggregate number of units to be reallocated from the PG&E CORP Phantom Stock Fund to another Investment Fund and for distributions from the Plan, shall be the closing price of a share of PG&E CORP common stock as traded on the New York Stock Exchange on the date that (i) amounts are credited to a Director's Account in the PG&E CORP Phantom Stock Fund, or (ii) the Plan Administrator receives a reallocation request, in the case of reallocations. If such credit or reallocation occurs after close of the New York Stock Exchange on that day, the price shall be based on the closing price of a share of PG&E CORP common stock on the next day on which such shares are traded on the New York Stock Exchange. Thereafter, the value of a unit shall fluctuate in accordance with the closing price of PG&E CORP common stock on the New York Stock Exchange. Each time that PG&E CORP pays a dividend on its common stock, an amount equal to such dividend payable with respect to each share of PG&E CORP common stock, multiplied by the number of units credited to a Director's Account, shall be credited to the Director's Account and converted into additional units. The number of additional units shall be calculated by dividing the aggregate amount of credited dividends, *i.e.*, the dividend multiplied by the number of units credited to the Director's Account as of the dividend record date, by the closing price of a share of PG&E CORP common stock on the New York Stock Exchange on the dividend payment date. If, after the record date but before the dividend payment date, a Director's balance in the PG&E CORP Phantom Stock Fund has been reallocated to another Investment Fund(s) or has been paid to the Director or to the Director's beneficiary, other than pursuant to an election under Section 7(c)(2) or 8, then an amount equal to the aggregated dividend shall be credited to the Director's Account in such other Investment Fund(s) or paid directly to the Director or the Director's beneficiary, whichever is applicable.

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2005 OFFICER SHORT-TERM INCENTIVE PLAN STRUCTURE

Background

At its meeting on December 15, 2004, the Nominating, Compensation, and Governance Committee reviewed and approved the 2005 Short-Term Incentive Plan (STIP) structure for officers of PG&E Corporation and Pacific Gas and Electric Company. The structure (*Attachment A*) establishes the weighting of corporate earnings from operations, subsidiary earnings from operations, and other performance factors for officers.

2005 Officer Short-Term Incentive Plan Structure ¹

Officer Group	Award Component	Weight	Performance Measures
PG&E Corporation	Corporate Financial Performance	100%	Corporate earnings from operations
Pacific Gas and Electric Company—Senior Officers (Officer Bands 2-4)	Corporate Financial Performance	25%	Corporate earnings from operations
	Utility Financial Performance	50%	Utility contribution to corporate earnings from operations
	Utility Operations Transformation	25%	Progress towards Utility Operations transformation
Pacific Gas and Electric Company—Officers (Officer Bands 5-6)	Corporate Financial Performance	25%	Corporate earnings from operations
	Utility Financial Performance	25%	Utility contribution to corporate earnings from operations
	Utility Operations Transformation	25%	Progress towards Utility Operations transformation
	Utility Operational Performance	25%	Financial, operating, and service measures determined by subsidiary CEO

¹ As with past STIP structures, the Chief Executive Officer of PG&E Corporation (CEO) will continue to have the discretion to modify the 2005 STIP structure for officers in circumstances where there is a need during the year to focus a particular officer on a key business-specific objective. Such discretion would be limited to shifting the performance measure weight proportionately such that no more than 25 percent would be assigned to the ancillary business-specific objective. In addition, the CEO will recommend to the Committee a performance rating for all qualitative award components (i.e., Utility Operations Transformation) based on his assessment of the performance for that award component. The Committee will continue to retain full discretion as to the determination of final officer STIP awards.

2005 OFFICER SHORT-TERM INCENTIVE PLAN STRUCTURE

ATTACHMENT A

2005 Officer Short-Term Incentive Plan Structure ¹

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Exhibit 10.20

**SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
OF
THE PACIFIC GAS AND ELECTRIC COMPANY**

This is the controlling and definitive statement of the Supplemental Executive Retirement Plan ("PLAN") ^{1/} for ELIGIBLE EMPLOYEES of Pacific Gas and Electric Company ("COMPANY") and such other companies, affiliates, subsidiaries, or associations as the BOARD OF DIRECTORS may designate from time to time. The PLAN was first adopted by the BOARD OF DIRECTORS in 1984 and was effective January 1, 1985. It has since been amended from time to time. Except as expressly stated by any amendment to this PLAN, benefits of ELIGIBLE EMPLOYEES who retire, terminate from employment, or cease to be ELIGIBLE EMPLOYEES prior to the effective date of any amendment shall not be affected by any such amendment. The amended PLAN as contained herein is effective December 31, 2004, and is frozen as of January 1, 2005.

^{1/} Words in all capitals are defined in Article I.

**ARTICLE I
DEFINITIONS**

1.01 *Basic SERP Benefit* shall mean the benefit described in Section 2.01.

1.02 *Beneficiary* shall mean the person, persons, or entity designated by the ELIGIBLE EMPLOYEE to receive payments under any optional form of benefit elected pursuant to Section 2.03 c. or Section 2.03 d., payable or owed but unpaid at the time of the ELIGIBLE EMPLOYEE's death. An ELIGIBLE EMPLOYEE shall designate a BENEFICIARY on a form provided by the PLAN ADMINISTRATOR and kept on file in the PLAN ADMINISTRATOR's office. An ELIGIBLE EMPLOYEE may change a BENEFICIARY at any time by filing a new beneficiary form with the PLAN ADMINISTRATOR.

1.03 *Board or Board of Directors* shall mean the BOARD OF DIRECTORS of the COMPANY or, when appropriate, any committee of the BOARD which has been delegated the authority to take action with respect to the PLAN.

1.04 *Company* shall mean the Pacific Gas and Electric Company, a California corporation.

1.05 *Eligible Employee* shall mean (1) employees of the COMPANY, or (2) with respect to PG&E Corporation and PG&E Corporation Support Services, Inc., employees who were transferred to PG&E Corporation or PG&E Corporation Support Services, Inc., from the COMPANY, (3) who are officers in Officer Bands I-V, and (4) such other employees of the COMPANY, or such other companies, affiliates, subsidiaries, or associations, as may be designated by the Chairman of the Board of the COMPANY. ELIGIBLE EMPLOYEES shall not include employees who are employed by the COMPANY, PG&E Corporation or PG&E Corporation Support Services, Inc. on or after January 1, 2005.

1.06 *STIP Payment* shall mean amounts received by an ELIGIBLE EMPLOYEE under the Short-Term Incentive Plan maintained by PG&E Corporation.

1.07 *Plan* shall mean the Supplemental Executive Retirement Plan ("SERP") as set forth herein and as may be amended from time to time.

1.08 *Plan Administrator* shall mean the Employee Benefit Finance Committee or such individual or individuals as that Committee may appoint to handle the day-to-day affairs of the PLAN.

1.09 *Retirement Plan* shall mean the Pacific Gas and Electric Company Retirement Plan for Management Employees.

1.10 *Salary* shall mean the base salary received by an ELIGIBLE EMPLOYEE. SALARY shall not include amounts received by an employee after such employee ceases to be an ELIGIBLE EMPLOYEE. For purposes of calculating benefits under the PLAN, SALARY shall not be reduced to reflect amounts which have been deferred under the PG&E Corporation Supplemental Retirement Savings Plan.

1.11 *Service* shall mean "credited service" as that term is defined in the RETIREMENT PLAN or, if the Nominating and Compensation Committee of the BOARD OF DIRECTORS has granted an adjusted service date for an ELIGIBLE EMPLOYEE, "credited service" as calculated from such adjusted service date. In no event, however, shall SERVICE include periods of time after which an officer has ceased to be an ELIGIBLE EMPLOYEE.

ARTICLE II SERP BENEFITS

2.01 The BASIC SERP BENEFIT payable from the PLAN shall be a monthly annuity commencing on the first of the month following the month in which the ELIGIBLE EMPLOYEE (i) attains his 65th birthday or (ii) ceases to be an employee of the COMPANY, whichever is later. The monthly amount of the BASIC SERP BENEFIT shall be equal to the product of:

$1.7\% \times [\text{average of three highest calendar years' combination of SALARY and STIP PAYMENT for the last ten years of SERVICE}] \times \text{SERVICE} \times \frac{1}{12}.$

In computing a year's combination of SALARY and STIP PAYMENT, the year's amount shall be the sum of the SALARY and STIP PAYMENT, if any, paid or payable in the same calendar year. If an ELIGIBLE EMPLOYEE has fewer than three years' SALARY, the average shall be the combination of SALARY and STIP PAYMENT for such shorter time, divided by the number of years and partial years during which such employee was an ELIGIBLE EMPLOYEE.

The BASIC SERP BENEFIT is further reduced by any amounts paid or payable from the RETIREMENT PLAN, calculated before adjustments for marital or joint pension option elections.

2.02 For ELIGIBLE EMPLOYEES of the COMPANY, PG&E Corporation, or PG&E Corporation Support Services, Inc., who transfer from any of said companies to another subsidiary or affiliate, the principles of Section 10 of the RETIREMENT PLAN shall govern the calculation of benefits under this PLAN. An ELIGIBLE EMPLOYEE who ceases to be an employee of the COMPANY and who is also not employed by any of its subsidiaries, affiliates, or related associations shall be entitled to receive a benefit payable from the PLAN at any time after his 55th birthday. The amount of the benefit payable shall be reduced by the appropriate age and service factors contained in the RETIREMENT PLAN applicable to such employee. For such calculations, the service factor shall be SERVICE as defined in the PLAN.

In computing amounts payable from the RETIREMENT PLAN as an offset to the benefit payable from this PLAN, the RETIREMENT PLAN benefit shall be calculated as though the ELIGIBLE EMPLOYEE elected to receive a pension from the RETIREMENT PLAN commencing on the same date as benefits from this PLAN.

2.03 An ELIGIBLE EMPLOYEE may elect to have his BASIC SERP BENEFIT paid in any one of the following forms:

- a. BASIC SERP BENEFIT, or a reduced BASIC SERP BENEFIT as calculated under Section 2.02, paid as a monthly annuity for the life of the ELIGIBLE EMPLOYEE with no survivor's benefit.

- b. A monthly annuity payable for the life of the ELIGIBLE EMPLOYEE with a survivor's option payable to the ELIGIBLE EMPLOYEE's joint annuitant beginning on the first of the month following the ELIGIBLE EMPLOYEE'S death. The factors to be applied to reduce the BASIC SERP BENEFIT to provide for a survivor's benefit shall be the factors which are contained in the RETIREMENT PLAN and which are appropriate given the type of joint pension elected and the ages and marital status of the joint annuitants.
- c. A five-year or ten-year certain annuity, with equal annual installment payments beginning on January 1 of the year following the year in which payments of the BASIC SERP BENEFIT would otherwise have commenced and continuing every January 1 thereafter until all payments are made. In determining the amount of the annuity payments, the present value of the BASIC SERP BENEFIT shall be computed using the appropriate mortality factors contained in the RETIREMENT PLAN for single life annuities and the interest rate set by the Pension Benefit Guaranty Corporation as of the first day of the year in which annuity payments begin.
- d. A lump sum payment of the actuarial present value of the BASIC SERP BENEFIT which would have been payable to the ELIGIBLE EMPLOYEE under Section 2.03 a. In determining the actuarial present value of the BASIC SERP BENEFIT, the PLAN ADMINISTRATOR shall apply the appropriate mortality factors used in calculating lump sum payments under the RETIREMENT PLAN for single life annuities and the interest rate set by the Pension Benefit Guaranty Corporation as of the first day of the year in which the lump sum payment is made.

2.04 Annuities payable to an ELIGIBLE EMPLOYEE who is receiving a (i) BASIC SERP BENEFIT, (ii) a BASIC SERP BENEFIT reduced to provide a survivor's benefit to a joint annuitant, or (iii) a joint annuitant who is receiving a survivor's benefit shall be decreased by any additional amounts which can be paid from the RETIREMENT PLAN where such additional amounts are due to increases in the limits placed on benefits payable from qualified pension plans under Section 415 of the Internal Revenue Code. The amount of any such decrease shall be adjusted to reflect the type of pension elected by an ELIGIBLE EMPLOYEE under the RETIREMENT PLAN and this PLAN. Decreases under this Section 2.04 shall not be applied to decrease benefits payable under the lump sum or the five-year or ten-year certain annuity options.

ARTICLE III DEATH BENEFITS

3.01 For an ELIGIBLE EMPLOYEE who has elected to receive his PLAN benefits in one of the optional forms described in Section 2.03 c. or 2.03 d. and who dies before receiving the total number of payments selected under the optional form of benefit, the PLAN ADMINISTRATOR shall continue to make the scheduled benefit payments to the BENEFICIARY designated by the ELIGIBLE EMPLOYEE. If the ELIGIBLE EMPLOYEE has failed to designate a BENEFICIARY or if there is no designated BENEFICIARY surviving at the time of the ELIGIBLE EMPLOYEE'S death, the PLAN ADMINISTRATOR shall make the remaining payments to the estate of the ELIGIBLE EMPLOYEE.

3.02 In the event that an ELIGIBLE EMPLOYEE who has accrued a benefit under this PLAN dies prior to the date that a BASIC SERP BENEFIT would otherwise commence and the ELIGIBLE EMPLOYEE is married at the time of the ELIGIBLE EMPLOYEE's death, the PLAN ADMINISTRATOR shall pay a spouse's benefit to the ELIGIBLE EMPLOYEE's surviving spouse:

- a. If the sum of the age and SERVICE of the ELIGIBLE EMPLOYEE at the time of death equaled 70 (69.5 or more is rounded to 70) or if the ELIGIBLE EMPLOYEE was age 55 at the time of death, the spouse's benefit shall be a monthly annuity commencing on the first of

the month following the month in which the ELIGIBLE EMPLOYEE dies and shall be payable for the life of the surviving spouse. The amount of the monthly benefit shall be one-half of the monthly BASIC SERP BENEFIT which would have been paid to the ELIGIBLE EMPLOYEE calculated:

- 1) as if he had elected to receive a BASIC SERP BENEFIT, without survivor's option;
 - 2) the monthly annuity starting date was the first of the month following the month in which the ELIGIBLE EMPLOYEE died; and
 - 3) without the application of early retirement reduction factors.
- b. If the ELIGIBLE EMPLOYEE is less than 55 years of age or had fewer than 70 points (as calculated under Section 3.02(a)) at the time of death, the surviving spouse will be entitled to receive a monthly annuity commencing on the first of the month following the month in which the ELIGIBLE EMPLOYEE would have become age 55 if he had survived. The amount of the monthly annuity payable to the surviving spouse shall be equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the ELIGIBLE EMPLOYEE had terminated employment at the date of death, 2) had lived until age 55, 3) had begun to receive PENSION payments, and 4) had subsequently died.
- c. If a former ELIGIBLE EMPLOYEE was age 55 or older at the time of his death and not yet receiving a SERP BENEFIT under the PLAN, the surviving spouse will be entitled to receive a monthly annuity in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if the former ELIGIBLE EMPLOYEE had begun receiving the converted SERP BENEFIT immediately prior to his death.
- d. If a former ELIGIBLE EMPLOYEE was younger than age 55 or had fewer than 70 points (as calculated under Section 3.02(a)) at the time of his death, the surviving spouse will be entitled to receive a monthly annuity in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the former ELIGIBLE EMPLOYEE had survived until age 55, 2) had begun receiving the converted SERP BENEFIT, and 3) had subsequently died.

3.03 A surviving spouse who is entitled to receive a spouse's benefit under Section 3.02 shall not be entitled to receive any other benefit under the PLAN.

ARTICLE IV ADMINISTRATIVE PROVISIONS

4.01 *Administration* . The PLAN shall be administered by the PLAN ADMINISTRATOR who shall have the authority to interpret the PLAN and make such rules as it deems appropriate. The PLAN ADMINISTRATOR shall have the duty and responsibility of maintaining records, making the requisite calculations, and disbursing payments hereunder. The PLAN ADMINISTRATOR's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

4.02 *Amendment and Termination* . The COMPANY may amend or terminate the PLAN at any time, provided, however, that no such amendment or termination shall adversely affect an accrued benefit which an ELIGIBLE EMPLOYEE has earned prior to the date of such amendment or termination, nor shall any amendment or termination adversely affect a benefit which is being provided to an ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or beneficiary under Article II or Article III on the date of such amendment or termination. Anything in this Section 4.02 to the contrary

notwithstanding, the COMPANY may reduce or terminate any benefit to which an ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or BENEFICIARY is or may become entitled provided that such ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or BENEFICIARY is or becomes entitled to an amount equal to such benefit under another plan, practice, or arrangement of the COMPANY.

4.03 *Nonassignability of Benefits* . The benefits payable under this PLAN or the right to receive future benefits under this PLAN may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a person eligible for any benefits becomes bankrupt, the interest under the PLAN of the person affected may be terminated by the PLAN ADMINISTRATOR which, in its sole discretion, may cause the same to be held if applied for the benefit of one or more of the dependents of such person or make any other disposition of such benefits that it deems appropriate.

4.04 *Nonguarantee of Employment* . Nothing contained in this PLAN shall be construed as a contract of employment between the COMPANY or the ELIGIBLE EMPLOYEE, or as a right of the ELIGIBLE EMPLOYEE to be continued in the employ of the COMPANY, to remain as an officer of the COMPANY, or as a limitation on the right of the COMPANY to discharge any of its employees, with or without cause.

4.05 *Benefits Unfunded and Unsecured* . The benefits under this PLAN are unfunded, and the interest under this PLAN of any ELIGIBLE EMPLOYEE and such ELIGIBLE EMPLOYEE's right to receive a distribution of benefits under this PLAN shall be an unsecured claim against the general assets of the COMPANY.

4.06 *Applicable Law* . All questions pertaining to the construction, validity, and effect of the PLAN shall be determined in accordance with the laws of the United States, and to the extent not preempted by such laws, by the laws of the State of California.

4.07 *Satisfaction of Claims* . Notwithstanding Section 4.05 or any other provision of the PLAN, the COMPANY may at any time satisfy its obligations (either on a before-tax or after-tax basis) for any benefits accrued under the PLAN by the purchase from an insurance company of an annuity contract on behalf of an ELIGIBLE EMPLOYEE. Such purchase shall be in the sole discretion of the COMPANY and shall be subject to the ELIGIBLE EMPLOYEE'S acknowledgement that the COMPANY'S obligations to provide benefits hereunder have been discharged, without regard to the payments ultimately made under the contract. In the event of a purchase pursuant to this Section 4.07, the COMPANY may in its sole discretion make payments to or on behalf of an ELIGIBLE EMPLOYEE to defray the cost to such ELIGIBLE EMPLOYEE of any personal income tax in connection with the purchase.

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN OF THE PACIFIC GAS AND ELECTRIC COMPANY
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Exhibit 10.21

**SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
OF
PG&E CORPORATION**

This is the controlling and definitive statement of the Supplemental Executive Retirement Plan ("PLAN") ^{1/} for ELIGIBLE EMPLOYEES of PG&E Corporation ("CORPORATION"), Pacific Gas and Electric Company ("COMPANY") and such other companies, affiliates, subsidiaries, or associations as the BOARD OF DIRECTORS may designate from time to time. The PLAN is the successor plan to the Supplemental Executive Retirement Plan of the COMPANY. The PLAN as contained herein is effective January 1, 2005.

^{1/} Words in all capitals are defined in Article I.

**ARTICLE I
DEFINITIONS**

1.01 *Basic SERP Benefit* shall mean the benefit described in Section 2.01.

1.02 *Board or Board of Directors* shall mean the BOARD OF DIRECTORS of the CORPORATION or, when appropriate, any committee of the BOARD which has been delegated the authority to take action with respect to the PLAN.

1.03 *Company* shall mean the Pacific Gas and Electric Company, a California corporation.

1.04 *Corporation* shall mean PG&E Corporation, a California corporation.

1.05 *Eligible Employee* shall mean (1) employees of the COMPANY (or, with respect to the CORPORATION and PG&E Corporation Support Services, Inc., employees who were transferred to the CORPORATION or PG&E Corporation Support Services, Inc., from the COMPANY), (2) who are officers in Officer Bands I-V, and (3) such other employees of the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc. or such other companies, affiliates, subsidiaries, or associations, as may be designated by the Chairman of the Board of the CORPORATION. ELIGIBLE EMPLOYEES shall not include employees who retired prior to January 1, 2005, or whose employment relationship with any of the PARTICIPATING EMPLOYERS was otherwise terminated prior to January 1, 2005.

1.06 *STIP Payment* shall mean amounts received by an ELIGIBLE EMPLOYEE under the Short-Term Incentive Plan maintained by the CORPORATION.

1.07 *Participating Employer* shall mean the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc., and any other companies, affiliates, subsidiaries or associations designated by the Chairman of the Board of the CORPORATION.

1.08 *Plan* shall mean the Supplemental Executive Retirement Plan ("SERP") as set forth herein and as may be amended from time to time.

1.09 *Plan Administrator* shall mean the Employee Benefit Committee or such individual or individuals as that Committee may appoint to handle the day-to-day affairs of the PLAN.

1.10 *Retirement Plan* shall mean the Pacific Gas and Electric Company Retirement Plan for Management Employees.

1.11 *Salary* shall mean the base salary received by an ELIGIBLE EMPLOYEE. SALARY shall not include amounts received by an employee after such employee ceases to be an ELIGIBLE EMPLOYEE. For purposes of calculating benefits under the PLAN, SALARY shall not be reduced to

reflect amounts that have been deferred under the PG&E Corporation Supplemental Retirement Savings Plan.

1.12 *Service* shall mean "credited service" as that term is defined in the RETIREMENT PLAN or, if the Nominating and Compensation Committee of the BOARD OF DIRECTORS has granted an adjusted service date for an ELIGIBLE EMPLOYEE, "credited service" as calculated from such adjusted service date. In no event, however, shall SERVICE include periods of time after which an officer has ceased to be an ELIGIBLE EMPLOYEE.

ARTICLE II

SERP BENEFITS

2.01 The BASIC SERP BENEFIT payable from the PLAN shall be a monthly annuity commencing on the later of the first of the seventh (7th) month following the month in which the ELIGIBLE EMPLOYEE ceases to be an employee of the PARTICIPATING EMPLOYER or the first of the month following the ELIGIBLE EMPLOYEE's 55th birthday. The monthly amount of the BASIC SERP BENEFIT shall be equal to the product of:

$1.7\% \times \text{the average of three highest calendar years' combination of SALARY and STIP PAYMENT for the last ten years of SERVICE} \times \text{SERVICE} \times \frac{1}{12}.$

In computing a year's combination of SALARY and STIP PAYMENT, the year's amount shall be the sum of the SALARY and STIP PAYMENT, if any, paid or payable in the same calendar year. If an ELIGIBLE EMPLOYEE has fewer than three years' SALARY, the average shall be the combination of SALARY and STIP PAYMENT for such shorter time, divided by the number of years and partial years during which such employee was an ELIGIBLE EMPLOYEE.

The BASIC SERP BENEFIT is further reduced by any amounts paid or payable from the RETIREMENT PLAN, calculated before adjustments for marital or joint pension option elections.

2.02 For ELIGIBLE EMPLOYEES of the PARTICIPATING EMPLOYERS, who transfer from any of said companies to another subsidiary or affiliate, the principles of Section 10 of the RETIREMENT PLAN shall govern the calculation of benefits under this PLAN. An ELIGIBLE EMPLOYEE who ceases to be an employee of a PARTICIPATING EMPLOYER and who is also not employed by any of the CORPORATION's subsidiaries, affiliates, or related associations shall be entitled to receive a benefit payable from the PLAN at any time after his 55th birthday. The amount of the benefit payable shall be reduced by the appropriate age and service factors contained in the RETIREMENT PLAN applicable to such employee. For such calculations, the service factor shall be SERVICE as defined in the PLAN.

In computing amounts payable from the RETIREMENT PLAN as an offset to the benefit payable from this PLAN, the RETIREMENT PLAN benefit shall be calculated as though the ELIGIBLE EMPLOYEE elected to receive a pension from the RETIREMENT PLAN commencing on the same date as benefits from this PLAN.

2.03 An ELIGIBLE EMPLOYEE may elect to have his BASIC SERP BENEFIT paid in any one of the following forms:

- a. BASIC SERP BENEFIT, or a reduced BASIC SERP BENEFIT as calculated under Section 2.02, paid as a monthly annuity for the life of the ELIGIBLE EMPLOYEE with no survivor's benefit.
- b. A monthly annuity payable for the life of the ELIGIBLE EMPLOYEE with a survivor's option payable to the ELIGIBLE EMPLOYEE's joint annuitant beginning on the first of the month following the ELIGIBLE EMPLOYEE'S death. The factors to be applied to reduce the BASIC SERP BENEFIT to provide for a survivor's benefit shall be the factors which are

contained in the RETIREMENT PLAN and which are appropriate given the type of joint pension elected and the ages and marital status of the joint annuitants.

2.04 Annuities payable to an ELIGIBLE EMPLOYEE who is receiving a (i) BASIC SERP BENEFIT, (ii) a BASIC SERP BENEFIT reduced to provide a survivor's benefit to a joint annuitant, or (iii) a joint annuitant who is receiving a survivor's benefit shall be decreased by any additional amounts which can be paid from the RETIREMENT PLAN where such additional amounts are due to increases in the limits placed on benefits payable from qualified pension plans under Section 415 of the Internal Revenue Code. The amount of any such decrease shall be adjusted to reflect the type of pension elected by an ELIGIBLE EMPLOYEE under the RETIREMENT PLAN and this PLAN.

ARTICLE III DEATH BENEFITS

3.01 In the event that an ELIGIBLE EMPLOYEE who has accrued a benefit under this PLAN dies prior to the date that a BASIC SERP BENEFIT would otherwise commence and the ELIGIBLE EMPLOYEE is married at the time of the ELIGIBLE EMPLOYEE's death, the PLAN ADMINISTRATOR shall pay a spouse's benefit to the ELIGIBLE EMPLOYEE's surviving spouse:

- a. If the sum of the age and SERVICE of the ELIGIBLE EMPLOYEE at the time of death equaled 70 (69.5 or more is rounded to 70) or if the ELIGIBLE EMPLOYEE was age 55 at the time of death, the spouse's benefit shall be a monthly annuity commencing on the first of the month following the month in which the ELIGIBLE EMPLOYEE dies and shall be payable for the life of the surviving spouse. The amount of the monthly benefit shall be one-half of the monthly BASIC SERP BENEFIT that would have been paid to the ELIGIBLE EMPLOYEE calculated:
 - 1) as if he had elected to receive a BASIC SERP BENEFIT, without survivor's option;
 - 2) the monthly annuity starting date was the first of the month following the month in which the ELIGIBLE EMPLOYEE died; and
 - 3) without the application of early retirement reduction factors.
- b. If the ELIGIBLE EMPLOYEE is less than 55 years of age or had fewer than 70 points (as calculated under Section 3.01(a)) at the time of death, the surviving spouse will be entitled to receive a monthly annuity commencing on the first of the month following the month in which the ELIGIBLE EMPLOYEE would have become age 55 if he had survived. The amount of the monthly annuity payable to the surviving spouse shall be equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the ELIGIBLE EMPLOYEE had terminated employment at the date of death, 2) had lived until age 55, 3) had begun to receive PENSION payments, and 4) had subsequently died.
- c. If a former ELIGIBLE EMPLOYEE was age 55 or older at the time of his death and not yet receiving a SERP BENEFIT under the PLAN, the surviving spouse will be entitled to receive a monthly annuity in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if the former ELIGIBLE EMPLOYEE had begun receiving the converted SERP BENEFIT immediately prior to his death.
- d. If a former ELIGIBLE EMPLOYEE was younger than age 55 or had fewer than 70 points (as calculated under Section 3.01(a)) at the time of his death, the surviving spouse will be entitled to receive a monthly annuity in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the

former ELIGIBLE EMPLOYEE had survived until age 55, 2) had begun receiving the converted SERP BENEFIT, and 3) had subsequently died.

3.02 A surviving spouse who is entitled to receive a spouse's benefit under Section 3.01 shall not be entitled to receive any other benefit under the PLAN.

ARTICLE IV ADMINISTRATIVE PROVISIONS

4.01 *Administration* . The PLAN shall be administered by the Senior Human Resources Officer of the CORPORATION ("PLAN ADMINISTRATOR"), who shall have the authority to interpret the PLAN and make and revise such rules as he or she deems appropriate. The PLAN ADMINISTRATOR shall have the duty and responsibility of maintaining records, making the requisite calculations, and disbursing payments hereunder. The PLAN ADMINISTRATOR's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

4.02 *Amendment and Termination* . The CORPORATION may amend or terminate the PLAN at any time, provided, however, that no such amendment or termination shall adversely affect an accrued benefit which an ELIGIBLE EMPLOYEE has earned prior to the date of such amendment or termination, nor shall any amendment or termination adversely affect a benefit which is being provided to an ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or beneficiary under Article II or Article III on the date of such amendment or termination. Anything in this Section 4.02 to the contrary notwithstanding, the CORPORATION may reduce or terminate any benefit to which an ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant, is or may become entitled provided that such ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant is or becomes entitled to an amount equal to such benefit under another plan, practice, or arrangement of the CORPORATION.

4.03 *Nonassignability of Benefits* . Except to the extent otherwise directed by a domestic relations order that the Plan Administrator determines is a Qualified Domestic Relations Order under Section 401(a)(12) of the Internal Revenue Code, the benefits payable under this PLAN or the right to receive future benefits under this PLAN may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a person eligible for any benefits becomes bankrupt, the interest under the PLAN of the person affected may be terminated by the PLAN ADMINISTRATOR which, in its sole discretion, may cause the same to be held if applied for the benefit of one or more of the dependents of such person or make any other disposition of such benefits that it deems appropriate.

4.04 *Nonguarantee of Employment* . Nothing contained in this PLAN shall be construed as a contract of employment between a PARTICIPATING EMPLOYER and the ELIGIBLE EMPLOYEE, or as a right of the ELIGIBLE EMPLOYEE to be continued in the employ of a PARTICIPATING EMPLOYER, to remain as an officer of a PARTICIPATING EMPLOYER, or as a limitation on the right of a PARTICIPATING EMPLOYER to discharge any of its employees, with or without cause.

4.05 *Apportionment of Costs* . The costs of the PLAN may be equitably apportioned by the PLAN ADMINISTRATOR among the PARTICIPATING EMPLOYERS. Each PARTICIPATING EMPLOYER shall be responsible for making benefit payments pursuant to the PLAN on behalf of its ELIGIBLE EMPLOYEES or for reimbursing the CORPORATION for the cost of such payments, as determined by the CORPORATION in its sole discretion. In the event the respective PARTICIPATING EMPLOYER fails to make such payment or reimbursement, and the CORPORATION does not exercise its discretion to make the contribution on such PARTICIPATING EMPLOYER's behalf, future benefit accruals of the ELIGIBLE EMPLOYEES of that PARTICIPATING EMPLOYER shall be suspended. If at some future date, the PARTICIPATING EMPLOYER makes all past-due contributions, plus interest at a rate determined by the PLAN ADMINISTRATOR in his or her sole

discretion, the benefit accrual of its ELIGIBLE EMPLOYEES will be recognized for the period of the suspension.

4.06 *Benefits Unfunded and Unsecured* . The benefits under this PLAN are unfunded, and the interest under this PLAN of any ELIGIBLE EMPLOYEE and such ELIGIBLE EMPLOYEE's right to receive a distribution of benefits under this PLAN shall be an unsecured claim against the general assets of the CORPORATION.

4.07 *Applicable Law* . All questions pertaining to the construction, validity, and effect of the PLAN shall be determined in accordance with the laws of the United States, and to the extent not preempted by such laws, by the laws of the State of California.

4.08 *Satisfaction of Claims* . Notwithstanding Section 4.05 or any other provision of the PLAN, the CORPORATION may at any time satisfy its obligations (either on a before-tax or after-tax basis) for any benefits accrued under the PLAN by the purchase from an insurance company of an annuity contract on behalf of an ELIGIBLE EMPLOYEE. Such purchase shall be in the sole discretion of the CORPORATION and shall be subject to the ELIGIBLE EMPLOYEE'S acknowledgement that the CORPORATION's obligations to provide benefits hereunder have been discharged, without regard to the payments ultimately made under the contract. In the event of a purchase pursuant to this Section 4.07, the CORPORATION may in its sole discretion make payments to or on behalf of an ELIGIBLE EMPLOYEE to defray the cost to such ELIGIBLE EMPLOYEE of any personal income tax in connection with the purchase.

Adopted pursuant to the delegation contained in the Resolution of the Board of Directors of Pacific Gas and Electric Company dated December 15, 2004.

By: /s/ PETER A. DARBEE

Peter A. Darbee
President and Chief Executive Officer

SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN OF PG&E CORPORATION
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**PG&E CORPORATION
NON-EMPLOYEE DIRECTOR STOCK INCENTIVE PLAN
(As amended effective as of July 1, 2004)**

1. Purpose of the Plan

This is the controlling and definitive statement of the PG&E Corporation Non-Employee Director Stock Incentive Plan (hereinafter called the PLAN¹). The purpose of the PLAN is to advance the interests of the CORPORATION by providing NON-EMPLOYEE DIRECTORS with financial incentives to promote the success of its long-term (five to ten years) business objectives, and to increase their proprietary interest in the success of the CORPORATION. Inasmuch as the PLAN is designed to encourage financial performance and to improve the value of shareholders' investment in PG&E CORPORATION, the costs of the PLAN will be funded from corporate earnings.

¹ Capitalized words are defined in Section 15 hereof.

2. Formula Awards of Director Restricted Stock, Non-Qualified Stock Options and Phantom Stock to Non-Employee Directors

All awards of DIRECTOR RESTRICTED STOCK, NON-QUALIFIED STOCK OPTIONS and PHANTOM STOCK under the PLAN shall be automatic and non-discretionary, and shall be made strictly in accordance with the provisions contained herein. No person shall have any discretion to select which NON-EMPLOYEE DIRECTORS shall be granted DIRECTOR RESTRICTED STOCK, NON-QUALIFIED STOCK OPTIONS or PHANTOM STOCK. Further, no person shall have any discretion to determine the number of shares of DIRECTOR RESTRICTED STOCK awarded to a NON-EMPLOYEE DIRECTOR, and, except as otherwise provided in Section 4 with respect to a NON-EMPLOYEE DIRECTOR'S election to allocate formula awards between NON-QUALIFIED STOCK OPTIONS and PHANTOM STOCK, no person shall have any discretion to determine the number of shares underlying NON-QUALIFIED STOCK OPTIONS and PHANTOM STOCK awarded to a NON-EMPLOYEE DIRECTOR.

3. Awards of Director Restricted Stock

- (a) On the first business day of each calendar year beginning on January 1, 1998, during the duration of the PLAN, each person who is a NON-EMPLOYEE DIRECTOR on the first business day of the applicable calendar year shall receive a grant of DIRECTOR RESTRICTED STOCK in an amount to be determined in accordance with the formula set forth in this Section 3 (a). The number of shares of DIRECTOR RESTRICTED STOCK to be granted to each NON-EMPLOYEE DIRECTOR each calendar year shall be determined by (i) dividing thirty thousand dollars (\$30,000) by the FAIR MARKET VALUE of the COMMON STOCK on the first business day of the applicable calendar year, and (ii) rounding the resulting number down to the nearest whole share. No person shall receive more than one (1) grant of DIRECTOR RESTRICTED STOCK during any calendar year.
- (b) Shares of DIRECTOR RESTRICTED STOCK shall vest cumulatively as follows: (i) twenty percent (20%) of such shares on the first anniversary of the date of grant; (ii) forty percent (40%) of such shares on the second anniversary of the date of grant; (iii) sixty percent (60%) of such shares on the third anniversary of the date of grant; (iv) eighty percent (80%) of such shares on the fourth anniversary of the date of grant; and (v) one hundred percent (100%) of such shares on the fifth anniversary of the date of grant. Shares of DIRECTOR RESTRICTED STOCK may not be resold or otherwise transferred by a GRANTEE until such shares are vested in accordance with the provisions of this Section 3(b).

4. Annual Election to Receive Non-Qualified Stock Options and Phantom Stock

By December 31 of each calendar year during the term of the Plan, each person who is then a NON-EMPLOYEE DIRECTOR shall deliver to the Corporate Secretary a written election to

receive either NON-QUALIFIED STOCK OPTIONS or PHANTOM STOCK, or both, with an aggregate value of \$30,000, on the first business day of the following calendar year, provided the person continues to be a NON-EMPLOYEE DIRECTOR on the date the award would otherwise be made. A NON-EMPLOYEE DIRECTOR may allocate between NON-QUALIFIED STOCK OPTIONS and PHANTOM STOCK in minimum increments with a value equal to \$5,000, as determined in accordance with Section 5 below with respect to NON-QUALIFIED STOCK OPTIONS, and Section 6 below, with respect to PHANTOM STOCK. All awards of NON-QUALIFIED STOCK OPTIONS and PHANTOM STOCK made to NON-EMPLOYEE DIRECTORS shall comply with Section 5 and Section 6 below, respectively. A NON-EMPLOYEE DIRECTOR who has failed to make a timely election or who became a NON-EMPLOYEE DIRECTOR after December 31 shall be awarded NON-QUALIFIED STOCK OPTIONS and PHANTOM STOCK, each with a value of \$15,000 as determined in accordance with Section 5 and Section 6, respectively, provided that the NON-EMPLOYEE DIRECTOR continues to be a NON-EMPLOYEE DIRECTOR on the on the first business day of the following calendar year.

5. Grant of Non-Qualified Stock Options to Non-Employee Directors

- (a) On the first business day of each calendar year beginning on January 1, 1998, during the duration of the PLAN, each person who is then a NON-EMPLOYEE DIRECTOR and who has elected to receive an award of NON-QUALIFIED STOCK OPTIONS in accordance with Section 4, shall receive a grant of NON-QUALIFIED STOCK OPTIONS with an aggregate value equal to \$5,000, \$10,000, \$15,000, \$20,000, \$25,000, or \$30,000, as previously elected by the NON-EMPLOYEE DIRECTOR (or \$15,000 in the case of a NON-EMPLOYEE DIRECTOR who has failed to make a timely election in accordance with Section 4 or who became a NON-EMPLOYEE DIRECTOR after December 31) (the "Elected Option Value"). The number of shares subject to the NON-QUALIFIED STOCK OPTIONS shall be determined by dividing the Elected Option Value by the value of a NON-QUALIFIED STOCK OPTION to purchase a single share of PG&E Corporation common stock as of the first business day of the applicable calendar year. The per stock option value shall be calculated in accordance with the Black-Scholes stock option valuation method using the average preceding November closing price of PG&E Corporation stock and reducing the per option value so calculated by twenty percent. The resulting number of NON-QUALIFIED STOCK OPTIONS shall be rounded down to the nearest whole share. No person shall receive more than one grant of NON-QUALIFIED STOCK OPTIONS during any calendar year.
- (b) The OPTION PRICE of the COMMON STOCK subject under each NON-QUALIFIED STOCK OPTION shall be the FAIR MARKET VALUE of the COMMON STOCK on the date of grant. The exercise of any NON-QUALIFIED STOCK OPTION shall be contingent upon receipt by the CORPORATION of (i) cash, (ii) check, (iii) shares of COMMON STOCK, (iv) an executed exercise notice together with irrevocable instructions to a broker to either sell the shares subject to the NON-QUALIFIED STOCK OPTION or hold such shares as collateral for a margin loan and to promptly deliver to the CORPORATION the amount of sale or loan proceeds required to pay the OPTION PRICE, or (v) any combination of the foregoing in an amount equal to the full OPTION PRICE of the shares being purchased. For purposes of this paragraph, shares of COMMON STOCK that are delivered in payment of the OPTION PRICE must have been previously owned by the GRANTEE for a minimum of one year, and shall be valued at their FAIR MARKET VALUE as of the date of the exercise of the NON-QUALIFIED STOCK OPTION. The CORPORATION shall not make loans to any GRANTEE for the purpose of exercising NON-QUALIFIED STOCK OPTIONS.
- (c) Each NON-QUALIFIED STOCK OPTION granted under the Plan shall become exercisable and vested cumulatively as follows: (i) up to thirty-three percent (33%) of the NON-QUALIFIED STOCK OPTION may be exercised on or after the second anniversary of

the date of grant; (ii) up to sixty-six percent (66%) of the NON-QUALIFIED STOCK OPTION may be exercised on or after the third anniversary of the date of grant; and (iii) up to one hundred percent (100%) of the NON-QUALIFIED STOCK OPTION may be exercised on or after the fourth anniversary of the date of grant.

- (d) The term of each NON-QUALIFIED STOCK OPTION shall be ten years and one day from the date of grant, subject to earlier termination as provided in Section 9 hereof. Any provision of the PLAN to the contrary notwithstanding, no NON-QUALIFIED STOCK OPTION shall be exercised after the time limitations stated in this Section 5(d).

6. Awards of Phantom Stock to Non-Employee Directors

- (a) On the first business day of each calendar year beginning on January 1, 1998, during the duration of the PLAN, each person who is then a NON-EMPLOYEE DIRECTOR and who has elected to receive an award of PHANTOM STOCK in accordance with Section 4, shall be credited with an amount of PHANTOM STOCK with a value (as determined by the FAIR MARKET VALUE of the COMMON STOCK on the first business day of the applicable calendar year) equal to \$5,000, \$10,000, \$15,000, \$20,000, \$25,000, or \$30,000, as previously elected by the NON-EMPLOYEE DIRECTOR (the "Elected Phantom Stock Value"). The number of shares of PHANTOM STOCK (including fractions computed to three decimal places) to be granted to each NON-EMPLOYEE DIRECTOR each calendar year shall be determined by dividing the Elected Phantom Stock Value (or \$15,000 in the case of a NON-EMPLOYEE DIRECTOR who has failed to make a timely election in accordance with Section 4 or who became a NON-EMPLOYEE DIRECTOR after December 31) by the FAIR MARKET VALUE of the COMMON STOCK on the first business day of the applicable calendar year. No person shall receive more than one grant of PHANTOM STOCK during any calendar year. The shares of PHANTOM STOCK awarded to a NON-EMPLOYEE DIRECTOR shall be credited to a newly established PHANTOM STOCK account for the NON-EMPLOYEE DIRECTOR. Each share of PHANTOM STOCK shall be deemed to be equal to one share (or fraction thereof) of COMMON STOCK on the date of grant, and shall thereafter fluctuate in value in accordance with the FAIR MARKET VALUE of the COMMON STOCK.
- (b) Each NON-EMPLOYEE DIRECTOR'S PHANTOM STOCK account shall be credited quarterly on each dividend payment date with additional shares of PHANTOM STOCK (including fractions computed to three decimal places) determined by dividing (i) the aggregate amount of dividends, i.e., the dividend multiplied by the number of shares of PHANTOM STOCK credited to the participant's account as of the dividend record date, by (ii) by the FAIR MARKET VALUE of the COMMON STOCK on the dividend payment date.
- (c) Payment of the shares of PHANTOM STOCK credited to a NON-EMPLOYEE DIRECTOR'S PHANTOM STOCK account shall be made after the NON-EMPLOYEE DIRECTOR'S RETIREMENT, MANDATORY RETIREMENT, or TERMINATION by reason of death or disability and in accordance with Section 9 below. Payment shall be made only in the form of shares of COMMON STOCK equal to the number of shares of PHANTOM STOCK credited to the NON-EMPLOYEE DIRECTOR'S PHANTOM STOCK account on the date of distribution, rounded down to the nearest whole share. The NON-EMPLOYEE DIRECTOR may elect to receive the number of shares of COMMON STOCK to which he is entitled following RETIREMENT OR MANDATORY RETIREMENT in a lump sum distribution of the entire amount or in a series of ten or less approximately equal annual installments, provided that distribution shall commence no later than January of the year following the year in which the NON-EMPLOYEE DIRECTOR'S RETIREMENT or MANDATORY RETIREMENT occurred. Following a NON-EMPLOYEE

DIRECTOR'S death or disability, the shares to which the NON-EMPLOYEE DIRECTOR (or his estate) is entitled shall become payable in accordance with Section 9(a) below.

7. Shares of Stock Subject to the Plan

There shall be reserved for use under the PLAN and for the grant of any other INCENTIVE AWARDS pursuant to the PROGRAM (subject to the provisions of Section 10 hereof) a total of 49,389,230 shares of COMMON STOCK, which shares may be authorized but unissued shares of COMMON STOCK or issued shares of COMMON STOCK which shall have been reacquired by PG&E CORPORATION.

8. Dividend, Voting and Other Shareholder Rights

Except as otherwise provided in the PLAN, each GRANTEE shall have all of the rights of a shareholder of PG&E CORPORATION with respect to all outstanding shares of DIRECTOR RESTRICTED STOCK registered in his or her name, whether or not such shares are vested, including the right to receive dividends and other distributions paid or made with respect to such shares and the right to vote such shares. No GRANTEE shall have any of the rights of a shareholder of PG&E CORPORATION with respect to a NON-QUALIFIED STOCK OPTION until the shares acquired upon exercise of such NON-QUALIFIED STOCK OPTION have been issued and registered in his or her name. No GRANTEE shall have any of the rights of a shareholder of PG&E CORPORATION with respect to PHANTOM STOCK credited to the NON-EMPLOYEE DIRECTOR'S PHANTOM STOCK account under the Plan.

9. Termination of Status as a Non-Employee Director

- (a) In the event of a TERMINATION by reason of disability or death, (i) all shares of DIRECTOR RESTRICTED STOCK held by the GRANTEE shall become fully vested, notwithstanding the provisions of Section 3(b) hereof, and the GRANTEE (or the GRANTEE'S estate or a person who acquired the shares of DIRECTOR RESTRICTED STOCK by bequest or inheritance) shall have the right to resell or transfer such shares at any time, (ii) all NON-QUALIFIED STOCK OPTIONS held by the GRANTEE, to the extent that such NON-QUALIFIED STOCK OPTIONS have not previously expired or been exercised, shall become fully vested and exercisable, notwithstanding the provisions of Section 5(c) hereof, and the GRANTEE (or the GRANTEE'S estate or a person who acquired the right to exercise the NON-QUALIFIED STOCK OPTION by bequest or inheritance) shall have the right to exercise the NON-QUALIFIED STOCK OPTIONS at any time within their respective terms or within one (1) year after the date of the GRANTEE'S death or disability, whichever is shorter, and (iii) all shares of PHANTOM STOCK credited to the NON-EMPLOYEE DIRECTOR'S PHANTOM STOCK account shall immediately become payable to the GRANTEE (or the GRANTEE'S estate or a person who acquired the shares of PHANTOM STOCK by bequest or inheritance) in the form of a number of shares of COMMON STOCK equal to the number of shares of PHANTOM STOCK credited to the NON-EMPLOYEE DIRECTOR'S PHANTOM STOCK account, rounded down to the nearest whole share. The term "disability" shall, for the purposes of the PLAN, be defined in Section 22(e)(3) of the CODE.
- (b) In the event of a TERMINATION by reason of MANDATORY RETIREMENT, (i) all shares of DIRECTOR RESTRICTED STOCK held by the GRANTEE shall become fully vested, notwithstanding the provisions of Section 3(b) hereof, and the GRANTEE shall have the right to resell or transfer such shares at any time, (ii) the NON-QUALIFIED STOCK OPTIONS then held by the GRANTEE, to the extent that such NON-QUALIFIED STOCK OPTIONS have not previously expired or been exercised, shall become fully vested and exercisable, notwithstanding the provisions of Section 5(c) hereof, and the GRANTEE shall have the right to exercise the NON-QUALIFIED STOCK OPTIONS at any time within their respective terms or within five (5) years after such MANDATORY RETIREMENT, whichever is shorter;

and (iii) all shares of PHANTOM STOCK credited to the NON- EMPLOYEE DIRECTOR'S PHANTOM STOCK account shall become payable to the GRANTEE in accordance with Section 6(c) hereof.

- (c) In the event of a TERMINATION for any reason other than those specified in subparagraphs (a) and (b) above, (i) any unvested shares of DIRECTOR RESTRICTED STOCK granted hereunder shall be forfeited and the GRANTEE shall return to the CORPORATION for cancellation any stock certificates representing such forfeited shares which forfeited shares shall be deemed to be canceled and no longer outstanding as of the date of TERMINATION; and from and after the date of TERMINATION, the GRANTEE shall cease to be a shareholder with respect to such forfeited shares and shall have no dividend, voting or other rights with respect thereto, (ii) any NON-QUALIFIED STOCK OPTIONS granted hereunder that have not yet vested and become exercisable shall terminate, (iii) the GRANTEE shall have the right to exercise NON-QUALIFIED STOCK OPTIONS, to the extent that such NON-QUALIFIED STOCK OPTIONS have vested and become exercisable as of the date of TERMINATION, at any time within their respective terms or within three months after such TERMINATION, whichever is shorter, after which the NON-QUALIFIED STOCK OPTIONS shall terminate, and (iv) all shares of PHANTOM STOCK credited to the NON-EMPLOYEE DIRECTOR'S PHANTOM STOCK account shall be forfeited on the date of TERMINATION; provided, however, that if the TERMINATION results from the NON-EMPLOYEE DIRECTOR'S RETIREMENT, then the PHANTOM STOCK credited to the NON-EMPLOYEE DIRECTOR'S PHANTOM STOCK account shall become payable in accordance with Section 6(c) hereof.
- (d) Notwithstanding the provisions of subparagraphs (a) through (c) above, the BOARD OF DIRECTORS may, in its sole discretion, establish different terms and conditions pertaining to the effect of TERMINATION, to the extent permitted by applicable federal and state law.

10. Adjustments Upon Changes in Number or Value of Shares of Common Stock

If there are any changes in the number or value of shares of COMMON STOCK by reason of stock dividends, stock splits, reverse stock splits, recapitalizations, mergers, consolidations or other events that materially increase or decrease the number or value of issued and outstanding shares of COMMON STOCK, the BOARD OF DIRECTORS or COMMITTEE may make such adjustments as it shall deem appropriate, in order to prevent dilution or enlargement of rights.

11. Non-Transferability

NON-QUALIFIED STOCK OPTIONS, PHANTOM STOCK, and shares of DIRECTOR RESTRICTED STOCK that have not vested in accordance with the provisions of Section 3(b) hereof, shall not be transferable by the GRANTEE otherwise than by will or the laws of descent and distribution, or pursuant to a qualified domestic relations order as defined by the CODE, Title I of ERISA or the rules thereunder.

12. Change in Control

Upon the occurrence of a CHANGE IN CONTROL (as defined below), (i) any time periods relating to the vesting of any shares of DIRECTOR RESTRICTED STOCK granted hereunder shall be accelerated so that all such shares immediately become fully vested, (ii) any time periods relating to the vesting of NON-QUALIFIED STOCK OPTIONS granted hereunder shall be accelerated so that all such NON-QUALIFIED STOCK OPTIONS immediately become fully vested and exercisable for the remainder of their terms, and (iii) all shares of PHANTOM STOCK credited to the NON-EMPLOYEE DIRECTORS' PHANTOM STOCK accounts shall become payable in accordance with Section 6(c) hereof as if the CHANGE IN CONTROL constituted a RETIREMENT.

A "CHANGE IN CONTROL" shall be deemed to have occurred if:

- (a) any "person" (as such term is used in Sections 13(d) and 14(d)(2) of the EXCHANGE ACT, but excluding any benefit plan for EMPLOYEES or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the beneficial owner of securities of PG&E CORPORATION representing twenty percent (20%) or more of the combined voting power of PG&E CORPORATION's then outstanding securities;
- (b) during any two consecutive years, individuals who at the beginning of such a period constitute the BOARD OF DIRECTORS cease for any reason to constitute at least a majority of the BOARD OF DIRECTORS, unless the election, or the nomination for election by the shareholders of PG&E CORPORATION, of each new DIRECTOR was approved by a vote of at least two-thirds ($\frac{2}{3}$) of the DIRECTORS then still in office who were DIRECTORS at the beginning of the period; or

the shareholders of the CORPORATION shall have approved (i) any consolidation or merger of the CORPORATION other than a merger or consolidation which would result in the voting securities of the CORPORATION outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent of such surviving entity) at least 70 percent of the Combined Voting Power of the CORPORATION, such surviving entity or the parent of such surviving entity outstanding immediately after the merger or consolidation; (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the CORPORATION, or (iii) any plan or proposal for the liquidation or dissolution of the CORPORATION. For purposes of this paragraph, the term Combined Voting Power shall mean the combined voting power of the CORPORATION's or other relevant entity's then outstanding voting securities.

13. Amendment and Termination of the Plan

The BOARD OF DIRECTORS or the COMMITTEE may at any time suspend, terminate, modify or amend the PLAN in any respect; provided, however, that, to the extent necessary and desirable to comply with the CODE (or any other applicable law or regulation, including the requirements of any stock exchange on which the COMMON STOCK is listed or quoted), shareholder approval of any PLAN amendment shall be obtained in such a manner and to such a degree as is required by the applicable law or regulation.

No suspension, termination, modification or amendment of the PLAN may, without the consent of the GRANTEE, adversely affect his or her rights with respect to DIRECTOR RESTRICTED STOCK, NON-QUALIFIED STOCK OPTIONS or PHANTOM STOCK theretofore granted to such GRANTEE.

Except as provided in Section 2 hereof, the BOARD OF DIRECTORS or COMMITTEE may make such amendments or modifications in the terms and conditions of any grant of DIRECTOR RESTRICTED STOCK, NON-QUALIFIED STOCK OPTIONS or PHANTOM STOCK as it may deem advisable, or cancel or annul any grant of DIRECTOR RESTRICTED STOCK, NON-QUALIFIED STOCK OPTIONS or PHANTOM STOCK; provided, however, that no such amendment, modification, cancellation or annulment may, without the consent of the GRANTEE, adversely affect his or her rights with respect to such grant.

14. Effective Date of the Plan and Duration

This PLAN became effective as of January 1, 1996, upon approval by the shareholders of Pacific Gas and Electric Company at its Annual Meeting on April 17, 1996. Effective January 1, 1997, the PLAN was assumed by PG&E CORPORATION. At its meeting on December 17, 1997, the

BOARD OF DIRECTORS amended and restated the PLAN effective January 1, 1998, to (i) reflect the adoption of new RULE 16B-3 which became effective November 1, 1996, and (ii) provide automatic formula awards of NON-QUALIFIED STOCK OPTIONS and PHANTOM STOCK to NON-EMPLOYEE DIRECTORS within the limits of the PROGRAM as previously approved by shareholders in 1996. The PLAN was subsequently amended on October 21, 1998 and April 21, 1999.

Effective May 16, 2001, the PLAN, and the PROGRAM of which the PLAN is a part, were amended to add 15,000,000 shares of COMMON STOCK to the total number of shares of COMMON STOCK reserved for use under the PLAN and the PROGRAM. By resolution dated June 16, 2004 and effective July 1, 2004, the BOARD OF DIRECTORS increased the amount of equity awards automatically granted under the PLAN. Unless terminated sooner pursuant to Section 13 hereof, the PLAN shall terminate on December 31, 2005.

15. Definitions

- (a) BOARD OF DIRECTORS means the Board of Directors of PG&E CORPORATION.
- (b) CHANGE IN CONTROL has the meaning set forth in Section 12 hereof.
- (c) CODE means the Internal Revenue Code of 1986, as amended from time to time.
- (d) COMMITTEE means the Nominating and Compensation Committee of the BOARD OF DIRECTORS or any successor to such committee.
- (e) COMMON STOCK means common shares of PG&E CORPORATION with no par value and any class of common shares into which such common shares hereafter may be converted.
- (f) CORPORATION means PG&E CORPORATION, and any parent corporation (as defined in Section 424(e) of the CODE) or subsidiary corporation (as defined in Section 424(f) of the CODE).
- (g) DIRECTOR means any person who is a member of the BOARD OF DIRECTORS or the Board of Directors of any parent corporation (as defined in Section 424(e) of the CODE) which may hereafter be established, including an advisory, emeritus or honorary director.
- (h) DIRECTOR RESTRICTED STOCK means RESTRICTED STOCK granted to a NON-EMPLOYEE DIRECTOR under the PLAN.
- (i) EMPLOYEE means any person who is employed by the CORPORATION. The payment of a director's fee or consulting fee by the CORPORATION shall not be sufficient to constitute "employment" by the CORPORATION.
- (j) ERISA means the Employee Retirement Income Security Act of 1974, as amended.
- (k) EXCHANGE ACT means the Securities Exchange Act of 1934, as amended.
- (l) FAIR MARKET VALUE means the closing price of the COMMON STOCK reported on the New York Stock Exchange Composite Transactions for the date specified for determining such value.
- (m) GRANTEE means the NON-EMPLOYEE DIRECTOR receiving the DIRECTOR RESTRICTED STOCK, NON-QUALIFIED STOCK OPTIONS and PHANTOM STOCK or his or her legal representative, legatees, distributees or alternate payees, as the case may be.
- (n) MANDATORY RETIREMENT means retirement as a DIRECTOR at age 70 or at such other age as may be specified in the retirement policy for the BOARD OF DIRECTORS or the Board of Directors of any parent corporation which may hereafter be established (as the

case may be), as in effect at the time of a NON-EMPLOYEE DIRECTOR'S TERMINATION.

- (o) NON-EMPLOYEE DIRECTOR means a DIRECTOR who is not an EMPLOYEE.
- (p) NON-QUALIFIED STOCK OPTION means a option to purchase shares of COMMON STOCK which is not intended to qualify as an incentive stock option under Section 422 of the CODE.
- (q) PG&E CORPORATION means PG&E CORPORATION, a California corporation.
- (r) PHANTOM STOCK means allocated hypothetical shares of COMMON STOCK that can be converted at a future date into stock.
- (s) PLAN means this Non-Employee Director Stock Incentive Plan, as may be amended from time to time, or any successor plan which the COMMITTEE or BOARD OF DIRECTORS may adopt from time to time with respect to the grant of DIRECTOR RESTRICTED STOCK, NON-QUALIFIED STOCK OPTIONS, PHANTOM STOCK or other stock-based incentive awards under the PROGRAM.
- (t) PROGRAM means the PG&E Corporation Long-Term Incentive Program, as amended effective May 16, 2001, and as may be amended from time to time, pursuant to which this PLAN is adopted.
- (u) RESTRICTED STOCK means COMMON STOCK that is subject to forfeiture by the GRANTEE to the CORPORATION under such circumstances as may be specified by the COMMITTEE.
- (v) RETIREMENT means TERMINATION of service on the BOARD OF DIRECTORS after serving continuously for five consecutive years.
- (w) RULE 16b-3 means Rule 16b-3 under the EXCHANGE ACT or any successor to Rule 16b-3, as in effect when discretion is being exercised with respect to the PLAN.

TERMINATION occurs when a NON-EMPLOYEE DIRECTOR ceases to be a member of the BOARD OF DIRECTORS or the Board of Directors of any parent corporation which may hereafter be established (as the case may be).

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Exhibit 10.37

**PG&E CORPORATION
OFFICER SEVERANCE POLICY
(As Amended Effective as of January 1, 2005)**

1. *Purpose*

This is the controlling and definitive statement of the Officer Severance Policy of PG&E Corporation ("Policy"). Since Officers are employed at the will of PG&E Corporation ("Corporation") or a participating employer ("Employer"), their employment may be terminated at any time, with or without cause. The Policy, which was first adopted effective November 1, 1998, provides Officers of the Corporation and Employer in Officer Compensation Bands I through V ("Officers") with severance benefits if their employment is terminated. ^{1/} Severance benefits for officers not covered by this Policy will be provided under policies or programs developed by the appropriate lines of business in consultation with and the approval by the Senior Human Resources Officer of the Corporation.

The purpose of the Policy is to attract and retain senior management by defining terms and conditions for severance benefits, to provide severance benefits that are part of a competitive total compensation package, to provide consistent treatment for all terminated officers, and to minimize potential litigation costs associated with Officer termination of employment.

2. *Termination of Employment Not Following a Change in Control or Potential Change in Control*

(a) *Corporation or Employer's Obligations* . If the Corporation or an Employer exercises its right to terminate an Officer's employment without cause and such termination does not entitle Officer to payments under Section 3, the Officer shall be given thirty (30) days' advance written notice or pay in lieu thereof. Except as provided in Section 2(b) below, in consideration of the Officer's agreement to the obligations described in Section 2(d) below and to the arbitration provisions described in Section 12 below, the following payments and benefits shall also be provided to Officer: ^{2/}

^{1/} Severance benefits for Officers who are currently covered by an employment agreement will continue to be provided solely under such agreements until their expiration at which time this Policy will become effective for such Officers.

^{2/} Any payments made hereunder shall be less applicable taxes.

- (1) A lump sum severance payment equal to: ^{1/} 12 (the sum of the Officer's annual base compensation and the Officer's Short-Term Incentive Plan target award at the time of his or her termination) times (the number of months that Officer was employed by the Corporation or the Employer ("Severance Multiple")); provided, however, that the Severance Multiple shall be no less than 6, nor more than 24 for Officers in Officer Bands I, II, III, or more than 18 for Officers in Officer Bands IV or V. Annual base compensation shall mean the Officer's monthly base pay for the month in which the Officer is given notice of termination, multiplied by 12.
 - (2) If Officer is a participant in the Supplemental Executive Retirement Plan of PG&E Corporation (SERP) and Officer's age is less than 55 years, such portion of the amount described in the preceding Section 2(a)(1) to provide for additional years to Officer's age to age 55 shall be converted for purposes of calculating a benefit under the SERP. Any amount of severance payment remaining after conversion under this subsection shall be paid to Officer in a lump sum. The value of any amount so converted shall be calculated using the same actuarial factors used in calculating benefits under the Retirement Plan for Employees of Pacific Gas and Electric Company. If Officer is a participant in the SERP and if the additional age resulting from a conversion under Section 2(a)(2) does
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not result in an age of 55, Officer shall be paid the amount calculated under 2(a)(1) in a lump sum;

- (3) The incentive awards granted to Officer under the Corporation's Long-Term Incentive Program which have not yet vested as of the date of termination will continue to vest over a period of months equal to the Severance Multiple after the date of termination as if the Officer had remained employed for such period. For vested stock options as of the date of termination, the Officer shall have the right to exercise such stock options at any time within their respective terms or within five years after termination, whichever is shorter. For stock options that vest during a period of months equal to the Severance Multiple, the Officer shall have the right to exercise such options at any time within five years after termination. Any unvested incentive awards remaining at the end of such period shall be forfeited;
 - (5) For Officers in Officer Bands I, II or III, two thirds of the unvested Company stock units in the Officer's account in the Corporation's Deferred Compensation Plan for Officers which were awarded in connection with the Executive Stock Ownership Program requirements ("SISOPs") shall vest upon the Officer's termination, and one third shall be forfeited. For Officers in Officer Bands IV and V, one third of any unvested SISOPs shall vest upon the Officer's termination, and two thirds shall be forfeited. Unvested stock units attributable to SISOPs which become vested under this provision shall be distributed to Officer in accordance with the Deferred Compensation Plan after such stock units vest;
 - (6) For a period of 18 months, the Officer's COBRA premiums, if any;
 - (7) If Officer is terminated after serving consecutively for six months in a fiscal year, Officer shall be entitled to receive a prorated bonus under any short-term incentive plan in which such Officer participates, at the time such bonus would otherwise be paid, if any;
 - (8) To the extent not theretofore paid or provided, the Officer shall be paid or provided with any other amounts or benefits required to be paid or provided or which the Officer is eligible to receive under any plan, contract or agreement of the Corporation or Employer;
 - (9) Such career transition services as the Corporation's Senior Human Resources Officer shall determine is appropriate; and
 - (10) All acts required of the Employer under the Policy may be performed by the Corporation for itself and the Employer, and the costs of the Policy may be equitably apportioned by the Administrator among the Corporation and the other Employers. The Corporation shall be responsible for making payments and providing benefits pursuant to this Policy for Officers employed by the Corporation. Whenever the Employer is permitted or required under the terms of the Policy to do or perform any act, matter or thing, it shall be done and performed by any Officer or employee of the Employer who is thereunto duly authorized by the board of directors of the Employer. Each Employer shall be responsible for making payments and providing benefits pursuant to the Policy on behalf of its Officers or for reimbursing the Corporation for the cost of such payments or benefits, as determined by the Corporation in its sole discretion. In the event the respective Employer fails to make such payment or reimbursement, an Officer's (or other payee's) sole recourse shall be against the respective Employer, and not against the Corporation.
- (b) *Remedies* . An Officer shall be entitled to recover damages for late or nonpayment of amounts to which the Officer is entitled hereunder. The Officer shall also be entitled to seek specific performance of the obligations and any other applicable equitable or injunctive relief.

- (c) Section 2(a) shall not apply in the event that an Officer's employment is terminated "for cause." Except as used in Section 3 of this Policy, "for cause" means that the Corporation, in the case of an Officer employed by the Corporation, or Employer in the case of an Officer employed by an Employer, acting in good faith based upon information then known to it, determines that the Officer has engaged in, committed, or is responsible for (1) serious misconduct, gross negligence, theft, or fraud against the Corporation and/or an Employer; (2) refusal or unwillingness to perform his duties; (3) inappropriate conduct in violation of Corporation's equal employment opportunity policy; (4) conduct which reflects adversely upon, or making any remarks disparaging of, the Corporation, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries; (5) insubordination; (6) any willful act that is likely to have the effect of injuring the reputation, business, or business relationship of the Corporation or its subsidiaries or affiliates; (7) violation of any fiduciary duty; or (8) breach of any duty of loyalty; or (9) any breach of the restrictive covenants contained in Subsection 2(d) below. Upon termination "for cause," the Corporation, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries shall have no liability to the Officer other than for accrued salary, vacation benefits, and any vested rights the Officer may have under the benefit and compensation plans in which the Officer participates and under the general terms and conditions of the applicable plan.
- (d) *Obligations of Officer*
- (1) *Release of Claims.* There shall be no obligation to commence the payment of the amounts and benefits described in Section 2(a) until the latter of (1) the delivery by Officer to the Corporation a fully executed comprehensive general release of any and all known or unknown claims that he or she may have against the Corporation, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries and a covenant not to sue in the form prescribed by the Administrator, and (2) the expiration of any revocation period associated with the release to which the Officer may be entitled under law.
- (2) *Covenant Not to Compete .* (i) During the period of Officer's employment with the Corporation or its subsidiaries and for a period of months equal to the Severance Multiple thereafter (the "Restricted Period"), Officer shall not, in any county within the State of California or in any city, county or area outside the State of California within the United States or in the countries of Canada or Mexico, directly or indirectly, whether as partner, employee, consultant, creditor, shareholder, or other similar capacity, promote, participate, or engage in any activity or other business competitive with the Corporation's business or that of any of its subsidiaries or affiliates, without the prior written consent of the Corporation's Chief Executive Officer. Notwithstanding the foregoing, Officer may have an interest in any public company engaged in a competitive business so long as Officer does not own more than 2 percent of any class of securities of such company, Officer is not employed by and does not consult with, or becomes a director of, or otherwise engage in any activities for, such competing company.
- (ii) The Corporation and its subsidiaries presently conduct their businesses within each county in the State of California and in areas outside California that are located within the United States, and it is anticipated that the Corporation and its subsidiaries will also be conducting business within the countries of Canada and Mexico. Such covenants are necessary and reasonable in order to protect the Corporation and its subsidiaries in the conduct of their businesses. To the extent that the foregoing covenant or any provision of this Section 2(d)(2)(ii) shall be deemed illegal or unenforceable by a court or other tribunal of competent jurisdiction with respect to (i) any geographic area, (ii) any part of the time period covered by such covenant, (iii) any activity or capacity covered by such covenant, or (iv) any other term or provision of such covenant, such determination shall

not affect such covenant with respect to any other geographic area, time period, activity or other term or provision covered by or included in such covenant.

- (3) *Soliciting Customers and Employees* . During the Restricted Period, Officer shall not, directly or indirectly, solicit or contact any customer or any prospective customer of the Corporation or its subsidiaries or affiliates for any commercial pursuit that could be reasonably construed to be in competition with the Corporation, or induce, or attempt to induce, any employees, agents or consultants of or to the Corporation or any of its subsidiaries or affiliates to do anything from which Officer is restricted by reason of this covenant nor shall Officer, directly or indirectly, offer or aid to others to offer employment to, or interfere or attempt to interfere with any employment, consulting or agency relationship with, any employees, agents or consultants of the Corporation, its subsidiaries and affiliates, who received compensation of \$75,000 or more during the preceding six (6) months, to work for any business competitive with any business of the Corporation, its subsidiaries or affiliates.
- (4) *Confidentiality* . Officer shall not at any time (including after termination of employment) divulge to others, use to the detriment of the Corporation or its subsidiaries or affiliates, or use in any business competitive with any business of the Corporation or its subsidiaries or affiliates any trade secret, confidential or privileged information obtained during his employment with the Corporation or its subsidiaries or affiliates, without first obtaining the written consent of the Corporation's Chief Executive Officer. This paragraph covers but is not limited to discoveries, inventions (except as otherwise provided by California law), improvements, and writings, belonging to or relating to the affairs of the Corporation or of any of its subsidiaries or affiliates, or any marketing systems, customer lists or other marketing data. Officer shall, upon termination of employment for any reason, deliver to the Corporation all data, records and communications, and all drawings, models, prototypes or similar visual or conceptual presentations of any type, and all copies or duplicates thereof, relating to all matters contemplated by this paragraph.
- (5) *Assistance in Legal Proceedings* . During the Restricted Period, Officer shall, upon reasonable notice from the Corporation, furnish information and proper assistance (including testimony and document production) to the Corporation as may be reasonably required by the Corporation in connection with any legal, administrative or regulatory proceeding in which it or any of its subsidiaries or affiliates is, or may become, a party, or in connection with any filing or similar obligation of the Corporation imposed by any taxing, administrative or regulatory authority having jurisdiction, provided, however, that the Corporation shall pay all reasonable expenses incurred by Officer in complying with this paragraph.
- (6) *Remedies*. Upon Officer's failure to comply with the provisions of this Section 2(d), the Corporation shall have the right to immediately terminate any unpaid amounts or benefits described in Section 2(a) to Officer. In the event of such termination, the Corporation shall have no further obligations under this Policy and shall be entitled to recover damages. In the event of an Officer's breach or threatened breach of any of the covenants set forth in this Section 2(d), the Corporation shall also be entitled to specific performance by Officer of any such covenant and any other applicable equitable or injunctive relief.

3. *Termination of Employment Following a Change in Control or Potential Change in Control*

- (a) If an Executive Officer's employment by the Corporation or any subsidiary or successor of the Corporation shall be subject to an Involuntary Termination within the Covered Period, then the provisions of this Section 3 instead of Section 2 shall govern the obligations of the

Corporation as to the payments and benefits it shall provide to the Executive Officer. In the event that Executive Officer's employment with the Corporation or an employing subsidiary is terminated under circumstances which would not entitle Executive Officer to payments under this Section 3, Executive Officer shall only receive such benefits to which he is entitled under Section 2, if any. In no event shall Executive Officer be entitled to receive termination benefits under both this Section 3 and Section 2.

All the terms used in this Section 3 shall have the following meanings:

- (1) "Affiliate" shall mean any entity which owns or controls, is owned or is under common ownership or control with, the Corporation.
- (2) "Cause" shall mean (i) the willful and continued failure of the Executive Officer to perform substantially the Executive Officer's duties with the Corporation or one of its affiliates (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive Officer by the Board of Directors or the Chief Executive Officer of the Corporation which specifically identifies the manner in which the Board of Directors or Chief Executive Officer believes that the Executive Officer has not substantially performed the Executive Officer's duties; or (ii) the willful engaging by the Executive Officer in illegal conduct or gross misconduct which is materially demonstrably injurious to the Corporation.

For purposes of the provision, no act or failure to act, on the part of the Executive Officer, shall be considered "willful" unless it is done, or omitted to be done, by the Executive Officer in bad faith or without reasonable belief that the Executive Officer's action or omission was in the best interests of the Corporation. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board of Directors or upon the instructions of the Chief Executive Officer or a senior officer of the Corporation or based upon the advice of counsel for the Corporation shall be conclusively presumed to be done, or omitted to be done, by the Executive Officer in good faith and in the best interests of the Corporation. The cessation of employment of the Executive Officer shall not be deemed to be for Cause unless and until there shall have been delivered to the Executive Officer a copy of a resolution duly adopted by the affirmative vote of not less than three-quarters of the entire membership of the Board of Directors at a meeting of the Board of Directors called and held for such purpose (after reasonable notice is provided to the Executive Officer and the Executive Officer is given an opportunity, together with counsel, to be heard before the Board of Directors), finding that, in the good faith opinion of the Board of Directors, the Executive Officer is guilty of the conduct described in subparagraph (i) or (ii) above, and specifying the particulars thereof in detail.

- (3) "Change in Control" shall be deemed to have occurred if:
 - a) any "person" (as such term is used in Sections 13(d) and 14(d)(2) of the Securities Exchange Act of 1934, but excluding any benefit plan for employees or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the beneficial owner of securities of the Corporation representing 20 percent or more of the combined voting power of the Corporation's then outstanding securities;
 - b) during any two consecutive years, individuals who at the beginning of such a period constitute the Board of Directors of the Corporation cease for any reason to constitute at least a majority of the Board of Directors of the Corporation, unless the

election or the nomination for election by the shareholders of the Corporation, of each new Director was approved by a vote of at least two-thirds ($\frac{2}{3}$) of the Directors then still in office who were Directors at the beginning of the period; or

- c) the shareholders of the Corporation shall have approved (i) any consolidation or merger of the Corporation other than a merger or consolidation which would result in the voting securities of the Corporation outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity or any parent of such surviving entity) at least 70 percent of the Combined Voting Power of the Corporation, such surviving entity or the parent of such surviving entity outstanding immediately after such merger or consolidation; (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Corporation; or (iii) any plan or proposal for the liquidation or dissolution of the Corporation.
- (4) "Change in Control Date" shall mean the date on which a Change in Control occurs.
 - (5) "Combined Voting Power" shall mean the combined voting power of the Corporation's or other relevant entity's then outstanding voting securities.
 - (6) "Covered Period" shall mean the period commencing with the Change in Control Date and terminating two (2) years following said commencement; provided, however, that if a Change in Control occurs and Executive Officer's employment with the Corporation or the employing subsidiary is subject to an Involuntary Termination before the Change in Control Date but on or after a Potential Change in Control Date, and if it is reasonably demonstrated by the Executive Officer that such termination (i) was at the request of a third party who has taken steps reasonably calculated to effect a Change in Control, or (ii) otherwise arose in connection with or in anticipation of a Change in Control, then the Covered Period shall mean, as applied to Executive Officer, the two-year period beginning on the date immediately before the Potential Change in Control Date. In the case of termination of employment following a Potential Change in Control Date, references in the definition of "Good Reason" to conditions in effect immediately prior to a Change in Control shall be deemed to mean conditions in effect immediately prior to Executive Officer's termination.
 - (7) "Disability" shall mean the absence of the Executive Officer from the Executive Officer's duties with the Corporation or the employing subsidiary on a full-time basis for 180 consecutive business days as a result of incapacity due to physical or mental illness which is determined to be total and permanent by a physician selected by the Corporation or its insurers and acceptable to the Executive Officer or the Executive Officer's legal representative.
 - (8) "Executive Officer" shall mean officers of the Corporation at the level of Senior Vice President and above.
 - (9) "Good Reason" shall mean any one or more of the following which takes place within the Covered Period:
 - a) An adverse change in Executive Officer's status or position(s) as in effect immediately before a Change in Control or Potential Change in Control, including, without limitation, the assignment to the Executive Officer of any duties inconsistent in any respect with the Executive Officer's position (including status, offices, titles and reporting requirements, including reporting requirements under Section 16 of the Securities Exchange Act of 1934), authority, duties or responsibilities prior to a

Change in Control or Potential Change in Control, or any other action by the Corporation which results in the diminution in such position, authority, duties or responsibilities prior to a Change in Control or Potential Change in Control, excluding for this purpose an isolated, insubstantial and inadvertent action not taken in bad faith and which is remedied by the Corporation promptly after receipt of notice thereof given by the Executive Officer;

- b) Executive Officer's base salary is reduced from that provided to him immediately before the Change in Control Date or as the same may be increased from time to time thereafter, unless such reduction is part of an across-the-board reduction for all similarly situated executives, including executives of the other party to the transaction that results in the Change in Control;
 - c) Executive Officer's eligibility to participate in bonus, stock option, incentive award and other compensation plans which provide opportunities to receive compensation is diminished from that provided to him immediately before the Change in Control Date, unless substantially equal benefits are provided to Executive Officer under comparable compensation plans, or unless such reduction is part of an across-the-board reduction for all similarly situated executives, including executives of the other party to the transaction that results in the Change in Control;
 - d) The aggregate projected value of Executive Officer's employee benefits (including but not limited to supplemental and excess retirement programs, medical, dental, life insurance and long-term disability plans) and perquisites is diminished from that provided to him immediately before the Change in Control Date, unless such reduction is part of an across-the-board reduction for all similarly situated executives, including executives of the other party to the transaction that results in the Change in Control;
 - e) A change in Executive Officer's principal place of employment by Corporation (including its subsidiaries) to a location more than thirty-five miles from Executive Officer's principal place of employment immediately before the Change in Control Date;
 - f) A reasonable determination by the Board of Directors that, as a result of a Change in Control and a change in circumstances thereafter significantly affecting his position, he is unable to exercise the authorities, powers, function or duties attached to his position immediately before the Change in Control Date;
 - g) The failure of the Corporation to obtain the assumption of this Policy by any successor contemplated in Section 7, hereof; or
 - h) The material failure of the Corporation to fulfill its obligations under this Policy, to the extent not remedied in a reasonable period of time after the Corporation's receipt of written notice from Executive Officer specifying the material failure by the Corporation.
- (10) "Involuntary Termination" shall mean a termination (i) by the Corporation without Cause, or (ii) by Executive Officer following Good Reason; provided, however, the term "Involuntary Termination" shall not include termination of Executive Officer's employment due to Executive Officer's death, Disability, or voluntary retirement.
- (11) "Potential Change in Control" shall mean the earliest to occur of (i) the date on which the Corporation executes an agreement or letter of intent, where the consummation of the transaction described therein would result in the occurrence of a Change in Control,

(ii) the date on which the Board of Directors approves a transaction or series of transactions, the consummation of which would result in a Change in Control, or (iii) the date on which a tender offer for the Corporation's voting stock is publicly announced, the completion of which would result in a Change in Control; provided, however, that if such Potential Change in Control terminates by its terms, such transaction shall no longer constitute a Potential Change in Control.

(12) "Potential Change in Control Date" shall mean the date on which a Potential Change in Control occurs.

(13) "Reference Salary" shall mean the greater of (i) the annual rate of Executive Officer's base salary from the Corporation or the employing subsidiary in effect immediately before the date of Executive Officer's Involuntary Termination, or (ii) the annual rate of Executive Officer's base salary from the Corporation or the employing subsidiary in effect immediately before the Change in Control Date.

(14) "Termination Date" shall be the date specified in the written notice of termination of Executive Officer's employment given by either party in accordance with Section 3(b) of this Policy.

(b) *Notice of Termination* . During the Covered Period, in the event that the Corporation (including an employing subsidiary) or Executive Officer terminates Executive Officer's employment with the Corporation or Employer, the party terminating employment shall give written notice of termination to the other party, specifying the Termination Date and the specific termination provision in this Section 3 that is relied upon, if any, and setting forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of Executive Officer's employment under the provision so indicated. The Termination Date shall be determined as follows: (i) if Executive Officer's employment is terminated for Disability, thirty (30) days after a Notice of Termination is given (provided that Executive Officer shall not have returned to the full-time performance of Executive Officer's duties during such 30-day period); (ii) if Executive Officer's employment is terminated by the Corporation in an Involuntary Termination, five days after the date the Notice of Termination is received by Executive Officer; and (iii) (as defined in this Section 3) if Executive Officer's employment is terminated by the Corporation for Cause, the date specified in the Notice of Termination, provided, that the events or circumstances cited by the Board of Directors as constituting Cause are not cured by Executive Officer during any cure period that may be offered by the Board of Directors. The Date of Termination for a resignation of employment other than for Good Reason shall be the date set forth in the applicable notice, which shall be no earlier than ten (10) days after the date such notice is received by the Corporation, unless waived by the Corporation.

During the Covered Period, a notice of termination given by Executive Officer for Good Reason shall be given within three (3) months after occurrence of the event on which Executive Officer bases his notice of termination and shall provide a Termination Date not more than sixty (60) days after the notice of termination is given to the Corporation.

(c) *Corporation's Obligations* . If Executive Officer's employment by the Corporation or any Employer or successor of the Corporation shall be subject to an Involuntary Termination

within the Covered Period, then the Corporation shall provide Executive Officer the following benefits:

- (1) The Corporation shall pay to the Executive Officer a lump sum in cash within thirty (30) days after the Termination Date:
 - a) the sum of (1) any earned but unpaid base salary through the Termination Date at the rate in effect at the time of the notice of termination to the extent not theretofore paid; (2) the Executive Officer's target bonus under the Short-Term Incentive Plan of the Corporation, an Affiliate, or a predecessor, for the fiscal year in which the Termination Date occurs (the "Target Bonus"); and (3) any accrued but unpaid vacation pay, in each case to the extent not theretofore paid; and
 - b) the amount equal to the product of (1) three and (2) the sum of (x) the Reference Salary and (y) the Target Bonus.
- (2) *Remedies* . The Executive Officer shall be entitled to recover damages for late or nonpayment of amounts which the Corporation is obligated to pay hereunder. The Executive Officer shall also be entitled to seek specific performance of the Corporation's obligations and any other applicable equitable or injunctive relief.
- (d) *Adjustment for Excise Taxes* . If any portion of the payments to the Executive Officer under this Section 3 or under any other plan, program, or arrangement maintained by the Corporation (a "Payment") would be subject to the excise tax levied under Section 4999 of the Internal Revenue Code ("Code"), or any interest or penalties are incurred by Executive Officer with respect to such excise tax (such excise tax together with such interest and penalties are referred to herein as the "Excise Tax"), then the Corporation shall make an additional payment to Executive Officer (a "Tax Restoration Payment") in an amount such that after payment by the Executive Officer of all taxes (including any interest or penalties imposed with respect to such taxes), including, without limitation, any income taxes (and any interest and penalties imposed with respect thereto) and Excise Tax imposed upon the Tax Restoration Payment, the Executive Officer retains an amount of the Tax Restoration Payment equal to the Excise Tax imposed upon the Payments. The payment of a Tax Restoration Payment under this Section 3 shall not be conditioned upon the Executive Officer's termination of employment.

All determinations and calculations required to be made under this Section 3(d) shall be made by Deloitte & Touche (the "Accounting Firm"), which shall provide its determination (the "Determination"), together with detailed supporting calculations regarding the amount of any Tax Restoration Payment and any other relevant matter, both to the Corporation and the Executive Officer within five (5) days of the termination of the Executive Officer's employment, if applicable, or such earlier time as is requested by the Corporation or the Executive Officer (if the Executive Officer reasonably believes that any of the Payments may be subject to Excise Tax). If the Accounting Firm determines that no Excise Tax is payable by the Executive Officer, it shall furnish the Executive Officer with a written statement that such Accounting Firm has concluded that no Excise Tax is payable (including the reasons therefor) and that the Executive Officer has substantial authority not to report any Excise Tax on the Executive Officer's federal income tax return. If a Tax Restoration Payment is determined to be payable, it shall be paid to the Executive Officer within five (5) days after the Determination is delivered to the Corporation or the Executive Officer. Any determination by the Accounting Firm shall be binding upon the Corporation and the Executive Officer, absent manifest error.

As a result of uncertainty in the application of Section 4999 of the Code at the time of the initial determination by the Accounting Firm hereunder, it is possible that Tax Restoration Payments not made by the Corporation should have been made ("Underpayment") or that Tax Restoration Payments will have been made by the Corporation which should not have been made ("Overpayment"). In either such event, the Accounting Firm shall determine the amount of the Underpayment or Overpayment that has occurred. In the case of an Underpayment, the amount of such Underpayment shall be promptly paid by the Corporation to or for the benefit of the Executive Officer. In the case of an Overpayment, the Executive Officer shall, at the direction and expense of the Corporation, take such steps as are reasonably necessary (including the filing of returns and claims for refund), follow reasonable instructions from, and procedures established by, the Corporation, and otherwise reasonably cooperate with the Corporation to correct such Overpayment, provided, however, that (i) the Executive Officer shall in no event be obligated to return to the Corporation an amount greater than the net after-tax portion of the Overpayment that the Executive Officer has retained or has recovered as a refund from the applicable taxing authorities, and (ii) this provision shall be interpreted in a manner consistent with the intent of the Tax Restoration Payment paragraph above, which is to make the Executive Officer whole, on an after-tax basis, from the application of Excise Tax, it being understood that the correction of an Overpayment may result in the Executive Officer's repaying to the Corporation an amount that is less than the Overpayment.

4. *Administration*

The Policy shall be administered by the Senior Human Resources Officer of the Corporation ("Administrator"), who shall have the authority to interpret the Policy and make and revise such rules as may be reasonably necessary to administer the Policy. The Administrator shall have the duty and responsibility of maintaining records, making the requisite calculations, securing Officer releases, and disbursing payments hereunder. The Administrator's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

5. *No Mitigation*

Payment of the amounts and benefits under Section 2(a) and Section 3 (except as otherwise provided in Section 2(a)(5)) shall not be subject to offset, counterclaim, recoupment, defense or other claim, right or action which the Corporation or an Employer may have and shall not be subject to a requirement that Officer mitigate or attempt to mitigate damages resulting from Officer's termination of employment.

6. *Amendment and Termination*

The Corporation, acting through its Nominating and Compensation Committee, reserves the right to amend or terminate the Policy at any time; provided, however, that any amendment which would reduce the aggregate level of benefits, or terminate the Policy, shall not become effective prior to the third anniversary of the Corporation giving notice to Officers of such amendment or termination.

7. *Successors*

The Corporation will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business or assets of the Corporation expressly to assume and to agree to perform its obligations under this Policy in the same manner and to the same extent that the Corporation would be required to perform such obligations if no such succession had taken place; provided, however, that no such assumption shall relieve the Corporation of its obligations hereunder. As used herein, the "Corporation" shall mean the Corporation as hereinbefore defined and any successor to its business and/or assets as aforesaid which assumes and agrees to perform its obligations by operation or law or otherwise.

This Policy shall inure to the benefit of and be binding upon the Officer (and Officer's personal representatives and heirs), Corporation and its successors and assigns, and any such successor or assignee shall be deemed substituted for the Corporation under the terms of this Policy for all purposes. As used herein, "successor" and "assignee" shall include any person, firm, corporation or other business entity which at any time, whether by purchase, merger or otherwise, directly or indirectly acquires the stock of the Corporation or to which the Corporation assigns this Policy by operation of law or otherwise. If Officer should die while any amount would still be payable to Officer hereunder if Officer had continued to live, all such amounts, unless otherwise provided herein, shall be paid in accordance with this Policy to Officer's devisee, legatee or other designee, or if there is no such designee, to Officer's estate.

8. *Nonassignability of Benefits*

The payments under this Policy or the right to receive future payments under this Policy may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a person eligible for payments becomes bankrupt, the payments under the Policy of the person affected may be terminated by the Administrator who, in his or her sole discretion, may cause the same to be held if applied for the benefit of one or more of the dependents of such person or make any other disposition of such benefits that he or she deems appropriate.

9. *Nonguarantee of Employment*

Officers covered by the Policy are at-will employees, and nothing contained in this Policy shall be construed as a contract of employment between the Officer and the Corporation (or, where applicable, a subsidiary or affiliate of the Corporation), or as a right of the Officer to continued employment, or to remain as an Officer, or as a limitation on the right of the Corporation (or a subsidiary or affiliate of the Corporation) to discharge Officer at any time, with or without cause.

10. *Benefits Unfunded and Unsecured*

The payments under this Policy are unfunded, and the interest under this Policy of any Officer and such Officer's right to receive payments under this Policy shall be an unsecured claim against the general assets of the Corporation.

11. *Applicable Law*

All questions pertaining to the construction, validity, and effect of the Policy shall be determined in accordance with the laws of the United States and, to the extent not preempted by such laws, by the laws of the state of California.

12. *Arbitration*

With the exception of any request for specific performance, injunctive or other equitable relief, any dispute or controversy of any kind arising out of or related to this Policy, Officer's employment with the Corporation (or with the employing subsidiary), the termination thereof or any claims for benefits shall be resolved exclusively by final and binding arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association then in effect. Provided, however, that in making their determination, the arbitrators shall be limited to accepting the position of the Officer or the position of the Corporation, as the case may be. The only claims not covered by this Section 12 are claims for benefits under workers' compensation or unemployment insurance laws; such claims will be resolved under those laws. The place of arbitration shall be San Francisco, California. Parties may be represented by legal counsel at the arbitration but must bear their own fees for such representation. The prevailing party in any dispute or controversy covered by this Section 12, or with respect to any request for specific performance, injunctive or other equitable relief, shall be entitled to recover, in addition to any other available remedies specified in this Policy, all litigation expenses and costs, including any arbitrator or administrative or filing fees and reasonable attorneys' fees. Both the Officer and the Corporation specifically waive any right to a jury trial on any dispute or controversy covered by this Section 12. Judgment may be entered on the arbitrators' award in any court of competent jurisdiction.

**PG&E CORPORATION
OFFICER GRANTOR TRUST AGREEMENT**

This Officer Grantor Trust Agreement (the "Trust Agreement") is made this 1st day of April 1998, by and between **PG&E CORPORATION** ("the Company") and **WACHOVIA BANK, N.A.** ("the Trustee").

Recitals

- (a) WHEREAS, the Company has adopted the nonqualified deferred compensation Plans and Agreements (the "Arrangements") as listed in Attachment I;
- (b) WHEREAS, the Company has incurred or expects to incur liability under the terms of such Arrangements with respect to the individuals participating in such Arrangements (the "Participants and Beneficiaries");
- (c) WHEREAS, the Company hereby establishes a Trust (the "Trust") and shall contribute to the Trust assets that shall be held therein, subject to the claims of the Company's creditors in the event of the Company's Insolvency, as herein defined, until paid to Participants and their Beneficiaries in such manner and at such times as specified in the Arrangements and in this Trust Agreement;
- (d) WHEREAS, it is the intention of the parties that this Trust shall constitute an unfunded arrangement and shall not affect the status of the Arrangements as an unfunded plan maintained for the purpose of providing deferred compensation for a select group of management or highly compensated employees for purposes of Title I of the Employee Retirement Income Security Act of 1974; and
- (e) WHEREAS, it is the intention of the Company to make contributions to the Trust to provide itself with a source of funds (the "Fund") to assist it in satisfying its Liabilities under the Arrangements.

NOW, THEREFORE, the parties do hereby establish the Trust and agree that the Trust shall be comprised, held and disposed of as follows:

Section 1. Establishment of The Trust

- (a) The Trust is intended to be a Grantor Trust, of which the Company is the Grantor, within the meaning of subpart E, part I, subchapter J, chapter 1, subtitle A of the Internal Revenue Code of 1986, as amended, and shall be construed accordingly.
 - (b) The Company shall be considered a Grantor for the purposes of the Trust.
 - (c) The Trust hereby established shall be irrevocable.
 - (d) The Company hereby deposits with the Trustee in the Trust One Thousand Dollars and Zero Cents (\$1,000.00) which shall become the principal of the Trust to be held, administered and disposed of by the Trustee as provided in this Trust Agreement.
 - (e) The principal of the Trust, and any earnings thereon shall be held separate and apart from other funds of the Company and shall be used exclusively for the uses and purposes of Participants and general creditors as herein set forth. Participants and their Beneficiaries shall have no preferred claim on, or any beneficial ownership interest in, any assets of the Trust. Any rights created under the Arrangements and this Trust Agreement shall be unsecured contractual rights of Participants and their Beneficiaries against the Company. Any assets held by the Trust will be subject to the claims of the general creditors of the Company under federal and state law in the event the Company is Insolvent, as defined in Section 3(a) herein.
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- (f) The Company, in its sole discretion, may at any time, or from time to time, make additional deposits of cash or other property acceptable to the Trustee in the Trust to augment the principal to be held, administered and disposed of by the Trustee as provided in this Trust Agreement. Prior to a Change of Control, neither the Trustee nor any Participant or Beneficiary shall have any right to compel additional deposits.
- (g) Upon a Change of Control, the Company shall, as soon as possible, but in no event longer than thirty (30) days following the occurrence of a Change of Control, as defined herein, make an irrevocable contribution to the Trust in an amount that is sufficient to fund the Trust in an amount equal to no less than 100% but no more than 120% of the amount necessary to pay each Participant or Beneficiary the benefits to which Participants or their Beneficiaries would be entitled pursuant to the terms of the Arrangements as of the date on which the Change of Control occurred. The Company shall also fund an expense reserve for the Trustee in the amount of \$225,000.00.

Section 2. *Payments Participants and Their Beneficiaries*

- (a) Prior to a Change of Control, distributions from the Trust shall be made by the Trustee to Participants and Beneficiaries at the direction of the Company. The entitlement of a Participant or his or her Beneficiaries to benefits under the Arrangements shall be determined by the Company or such party or professional administrator as it shall designate under the Arrangements as the Company's agent, and any claim for such benefits shall be considered and reviewed under the procedures set out in the Arrangements.
- (b) The Company may make payment of benefits directly to Participants or their Beneficiaries as they become due under the terms of the Arrangements. The Company shall notify the Trustee of its decision to make payment of benefits directly prior to the time amounts are payable to Participants or their Beneficiaries. In addition, if the principal of the Trust, and any earnings thereon, are not sufficient to make payments of benefits in accordance with the terms of the Arrangements, the Company shall make the balance of each such payment as it falls due in accordance with the Arrangements. The Trustee shall notify the Company where principal and earnings are not sufficient. Nothing in this Agreement shall relieve the Company of its liabilities to pay benefits due under the Arrangements except to the extent such liabilities are met by application of assets of the Trust.
- (c) After a Change of Control, the Company shall continue to make the determination of benefits due to Participants or their Beneficiaries and shall provide the Trustee with a schedule of benefits due. The Trustee shall pay benefits due in accordance with such schedule; provided however, a Participant or their Beneficiaries may make application to the Trustee for an independent decision as to the amount or form of their benefits due under the Arrangements. In making any determination required or permitted to be made by the Trustee under this Section, the Trustee shall, in each such case, reach its own independent determination, in its absolute and sole discretion, as to the Participant's or Beneficiary's entitlement to a payment hereunder. In making its determination, the Trustee may consult with and make such inquiries of such persons, including the Participant or Beneficiary, the Company, legal counsel, actuaries or other persons, as the Trustee may reasonably deem necessary. Any reasonable costs incurred by the Trustee in arriving at its determination shall be reimbursed by the Company and, to the extent not paid by the Company within a reasonable time, shall be charged to the Trust. The Company waives any right to contest any amount paid over by the Trustee hereunder pursuant to a good faith determination made by the Trustee notwithstanding any claim by or on behalf of the Company (absent a manifest abuse of discretion by the Trustee) that such payments should not be made.

- (d) The Trustee agrees that it will not itself institute any action at law or at equity, whether in the nature of an accounting, interpleading action, request for a declaratory judgment or otherwise, requesting a court or administrative or quasi-judicial body to make the determination required to be made by the Trustee under this Section 2 in the place and stead of the Trustee. The Trustee may institute an action to collect a contribution due the Trust following a Change of Control or in the event that the Trust should ever experience a short-fall in the amount of assets necessary to make payments pursuant to the terms of the Arrangements.
- (e) In the event any Participant or his or her Beneficiary is determined to be subject to federal income tax on any amount to the credit of his or her account under any Arrangement prior to the time of payment hereunder, whether or not due to the establishment of or contributions to this Trust, a portion of such taxable amount equal to the federal, state and local taxes (excluding any interest or penalties) owed on such taxable amount, shall be distributed by the Trustee as soon thereafter as practicable to such Participant or Beneficiary. The Company shall promptly reimburse the Trust for any such distribution in an amount certified by the Trustee to be needed for the Participant's benefits. For these purposes, a Participant or Beneficiary shall be deemed to pay state and local taxes at the highest marginal rate of taxation in the state in which the Participant resides or is employed (or both) where a tax is imposed and federal income taxes at the highest marginal rate of taxation, net of the maximum reduction in federal income taxes which could be obtained from deduction of such state and local taxes. Such distributions shall be at the direction of the Company or the Trustee, or upon proper application of the Participant or Beneficiary; provided that the actual amount of the distribution shall be determined by the Company prior to a Change of Control and the Trustee following a Change of Control. An amount to the credit of a Participant's Account shall be determined to be subject to federal income tax upon the earliest of: (a) a final determination by the United States Internal Revenue Service addressed to the Participant or his Beneficiary which is not appealed to the courts; (b) a final determination by the United States Tax Court or any other federal court affirming any such determination by the Internal Revenue Service; or (c) an opinion by the Company's tax counsel, addressed to the Company and the Trustee, to the effect that by reason of Treasury Regulations, amendments to the Internal Revenue Code, published Internal Revenue Service rulings, court decisions or other substantial precedent, amounts to the credit of Participants hereunder are subject to federal income tax prior to payment. The Company may undertake at its sole expense to defend any tax claims described herein which are asserted by the Internal Revenue Service against any Participant or Beneficiary, including attorney fees and cost of appeal, and shall have the sole authority to determine whether or not to appeal any determination made by the Service or by a lower court. The Company also agrees to reimburse any Participant or Beneficiary for any interest or penalties in respect of tax claims hereunder upon receipt of documentation of same. Any distributions from the Fund to a Participant or Beneficiary under this Section 2(e) shall be applied in accordance with the provisions of the Arrangement to reduce the Company liabilities to such Participant and/or Beneficiary under the Arrangement with such reductions to be made on a pro-rata basis over the term of benefit payments under the Arrangement; provided, however, that in no event shall any Participant, Beneficiary or estate of any Participant or Beneficiary have any obligation to return all or any part of such distribution to the Company if such distribution exceeds benefits payable under an Arrangement. Any reduction in accordance with the foregoing sentence and the Arrangements shall be determined by the Company prior to a Change of Control. Following a Change of Control, the Company shall continue to make such determination subject to the right of a Participant to petition the Trustee under Section 2(c).

Section 3. Trustee Responsibility Regarding Payments To The Trust Beneficiary When The Company Is Insolvent

- (a) The Trustee shall cease payment of benefits to Participants and their Beneficiaries if the Company is Insolvent. The Company shall be considered "Insolvent" for purposes of this Trust Agreement if (i) the Company is unable to pay its debts as they become due, or (ii) the Company is subject to a pending proceeding as a debtor under the United States Bankruptcy Code.
- (b) At all times during the continuance of this Trust, the principal and income of the Trust shall be subject to claims of general creditors of the Company under federal and state law as set forth below.
 - (1) The Board of Directors and the Chief Executive Officer of the Company shall have the duty to inform the Trustee in writing that the Company is Insolvent. If a person claiming to be a creditor of the Company alleges in writing to the Trustee that the Company has become Insolvent, the Trustee shall determine whether the Company is Insolvent and, pending such determination, the Trustee shall discontinue payment of benefits to Participants or their Beneficiaries.
 - (2) Unless the Trustee has actual knowledge that the Company is Insolvent, or has received notice from the Company or a person claiming to be a creditor alleging that the Company is Insolvent, the Trustee shall have no duty to inquire whether the Company is Insolvent. The Trustee may in all events rely on such evidence concerning the Company's solvency as may be furnished to the Trustee and that provides the Trustee with a reasonable basis for making a determination concerning the Company's solvency.
 - (3) If at any time the Trustee has determined that the Company is Insolvent, the Trustee shall discontinue payments to Participants or their Beneficiaries and shall hold the assets of the Trust for the benefit of the Company's general creditors. Nothing in this Trust Agreement shall in any way diminish any rights of Participants or their Beneficiaries to pursue their rights as general creditors of the Company with respect to benefits due under the Arrangements or otherwise.
 - (4) The Trustee shall resume the payment of benefits to Participants or their Beneficiaries in accordance with Section 2 of this Trust Agreement only after the Trustee has determined that the Company is not Insolvent (or is no longer Insolvent).
- (c) Provided that there are sufficient assets, if the Trustee discontinues the payment of benefits from the Trust pursuant to Section 3(b) hereof and subsequently resumes such payments, the first payment following such discontinuance shall include the aggregate amount of all payments due to Participants or their Beneficiaries under the terms of the Arrangements for the period of such discontinuance, less the aggregate amount of any payments made to Participants or their Beneficiaries by the Company in lieu of the payments provided for hereunder during any such period of discontinuance.

Section 4. Payments if a Short-Fall of The Trust Assets Occurs

- (a) If there are not sufficient assets for the payment of benefits pursuant to Section 2 or Section 3(c) hereof and the Company does not otherwise make such payments within a reasonable time after demand from the Trustee, the Trustee shall make payment of benefits from the Trust to the Participants or their Beneficiaries in the following order of priority:
 - (1) retired Participants and their Beneficiaries;
 - (2) vested Participants over the age of 55 who were terminated within two years following a Change of Control and their Beneficiaries;

- (3) vested active Participants over the age of 55 and their Beneficiaries;
 - (4) any other vested active Participants and their Beneficiaries;
 - (5) vested former Participants and their Beneficiaries; and
 - (6) non-vested Participants and their Beneficiaries
- (b) Within each category set forth under Section 4(a), payments shall be prioritized in the following order:
- (c) Upon receipt of a contribution from the Company necessary to make up for a short-fall in the payments due, the Trustee shall resume payments to all the Participants and Beneficiaries under the Arrangements. Following a Change of Control, the Trustee shall have the right to compel a contribution to the Trust from the Company to make-up for any short-fall.

Section 5. *Payments to the Company*

Except as provided in Sections 3, 8, and 14 hereof, the Company shall have no right or power to direct the Trustee to return to the Company or to divert to others any of the Trust assets before all payment of benefits have been made to Participants and their Beneficiaries pursuant to the terms of the Arrangements.

Section 6. *Investment Authority*

- (a) The Trustee shall not be liable in discharging its duties hereunder, including without limitation its duty to invest and reinvest the Fund, if it acts for the exclusive benefit of the Participants and their Beneficiaries, in good faith and as a prudent person would act in accomplishing a similar task and in accordance with the terms of this Trust Agreement and any applicable federal or state laws, rules or regulations.
- (b) Subject to investment guidelines agreed to in writing from time to time by the Company and the Trustee prior to a Change of Control, the Trustee shall have the power in investing and reinvesting the Fund in its sole discretion:
- (1) To invest and reinvest in any readily marketable common and preferred stocks, bonds, notes, debentures (including convertible stocks and securities but not including any stock or security of other than a de minimus amount held in a collective or mutual fund), certificates of deposit or demand or time deposits (including any such deposits with the Trustee) and shares of investment companies and mutual funds, without being limited to the classes or property in which the Trustees are authorized to invest by any law or any rule of court of any state and without regard to the proportion any such property may bear to the entire amount of the Fund;
 - (2) To commingle for investment purposes all or any portion of the Fund with assets of any other similar trust or trusts established by the Company with the Trustee for the purpose of safeguarding deferred compensation or retirement income benefits of its employees and/or directors;
 - (3) To retain any property at any time received by the Trustee;
 - (4) To sell or exchange any property held by it at public or private sale, for cash or on credit, to grant and exercise options for the purchase or exchange thereof, to exercise all conversion or subscription rights pertaining to any such property and to enter into any covenant or agreement to purchase any property in the future;

- (5) To participate in any plan of reorganization, consolidation, merger, combination, liquidation or other similar plan relating to property held by it and to consent to or oppose any such plan or any action thereunder or any contract, lease, mortgage, purchase, sale or other action by any person;
- (6) To deposit any property held by it with any protective, reorganization or similar committee, to delegate discretionary power thereto, and to pay part of the expenses and compensation thereof any assessments levied with respect to any such property to deposited;
- (7) To extend the time of payment of any obligation held by it;
- (8) To hold uninvested any moneys received by it, without liability for interest thereon, but only in anticipation of payments due for investments, reinvestments, expenses or disbursements;
- (9) To exercise all voting or other rights with respect to any property held by it and to grant proxies, discretionary or otherwise;
- (10) For the purposes of the Trust, to borrow money from others, to issue its promissory note or notes therefor, and to secure the repayment thereof by pledging any property held by it;
- (11) To employ suitable contractors and counsel, who may be counsel to the Company or to the Trustee, and to pay their reasonable expenses and compensation from the Fund to the extent not paid by the Company;
- (12) To register investments in its own name or in the name of a nominee; to hold any investment in bearer form; and to combine certificates representing securities with certificates of the same issue held by it in other fiduciary capacities or to deposit or to arrange for the deposit of such securities with any depository, even though, when so deposited, such securities may be held in the name of the nominee of such depository with other securities deposited therewith by other persons, or to deposit or to arrange for the deposit of any securities issued or guaranteed by the United States government, or any agency or instrumentality thereof, including securities evidenced by book entries rather than by certificates, with the United States Department of the Treasury or a Federal Reserve Bank, even though, when so deposited, such securities may not be held separate from securities deposited therein by other persons; provided, however, that no securities held in the Fund shall be deposited with the United States Department of the Treasury or a Federal Reserve Bank or other depository in the same account as any individual property of the Trustee, and provided, further, that the books and records of the Trustee shall at all times show that all such securities are part of the Trust Fund;
- (13) To settle, compromise or submit to arbitration any claims, debts or damages due or owing to or from the Trust, respectively, to commence or defend suits or legal proceedings to protect any interest of the Trust, and to represent the Trust in all suits or legal proceedings in any court or before any other body or tribunal; provided, however, that the Trustee shall not be required to take any such action unless it shall have been indemnified by the Company to its reasonable satisfaction against liability or expenses it might incur therefrom;
- (14) To hold and retain policies of life insurance, annuity contracts, and other property of any kind which policies are contributed to the Trust by the Company or any subsidiary of the Company or are purchased by the Trustee;
- (15) To hold any other class of assets which may be contributed by the Company and that is deemed reasonable by the Trustee, unless expressly prohibited herein;
- (16) To loan any securities at any time held by it to brokers or dealers upon such security as may be deemed advisable, and during the terms of any such loan to permit the loaned securities to be transferred into the name of and voted by the borrower or others; and

- (17) Generally, to do all acts, whether or not expressly authorized, that the Trustee may deem necessary or desirable for the protection of the Fund.
- (c) Prior to a Change of Control, the Company shall have the right, subject to this Section to direct the Trustee with respect to investments.
- (1) The Company may at any time direct the Trustee to segregate all or a portion of the Fund in a separate investment account or accounts and may appoint one or more investment managers and/or an Investment Committee established by the Company as described in Section 6(d) hereof to direct the investment and reinvestment of each such investment account or accounts. In such event, the Company shall notify the Trustee of the appointment of each such investment manager and/or Investment Committee. No such investment manager shall be related, directly or indirectly, to the Company, but members of the Investment Committee may be employees of the Company.
 - (2) Thereafter, the Trustee shall make every sale or investment with respect to such investment account as directed in writing by the investment manager or Investment Committee. It shall be the duty of the Trustee to act strictly in accordance with each direction. The Trustee shall be under no duty to question any such direction of the investment manager or Investment Committee, to review any securities or other property held in such investment account or accounts acquired by it pursuant to such directions or to make any recommendations to the investment managers or Investment Committee with respect to such securities or other property.
 - (3) Notwithstanding the foregoing, the Trustee, without obtaining prior approval or direction from an investment manager or Investment Committee, shall invest cash balances held by it from time to time in short term cash equivalents including, but not limited to, through the medium of any short term common, collective or commingled trust fund established and maintained by the Trustee subject to the instrument establishing such trust fund, U.S. Treasury Bills, commercial paper (including such forms of commercial paper as may be available through the Trustee's Trust Department), certificates of deposit (including certificates issued by the Trustee in its separate corporate capacity), and similar type securities, with a maturity not to exceed one year; and, furthermore, sell such short term investments as may be necessary to carry out the instructions of an investment manager or Investment Committee regarding more permanent type investment and directed distributions.
 - (4) The Trustee shall neither be liable nor responsible for any loss resulting to the Fund by reason of any sale or purchase of an investment directed by an investment manager or Investment Committee nor by reason of the failure to take any action with respect to any investment which was acquired pursuant to any such direction in the absence of further directions of such investment manager or Investment Committee.
 - (5) Notwithstanding anything in this Agreement to the contrary, the Trustee shall be indemnified and saved harmless by the Company from and against any and all personal liability to which the Trustee may be subjected by carrying out any directions of an investment manager or Investment Committee issued pursuant hereto or for failure to act in the absence of directions of the investment manager or Investment Committee including all expenses reasonably incurred in its defense in the event the Company fails to provide such defense; provided, however, the Trustee shall not be so indemnified if it participates knowingly in, or knowingly undertakes to conceal, an act or omission of an investment manager or Investment Committee, having actual knowledge that such act or omission is a breach of a fiduciary duty; provided further, however, that the Trustee shall not be deemed to have knowingly participated in or knowingly undertaken to conceal an act or omission of an investment manager or Investment Committee with knowledge that such act or omission was a breach of

fiduciary duty by merely complying with directions of an investment manager or Investment Committee or for failure to act in the absence of directions of an investment manager or Investment Committee. The Trustee may rely upon any order, certificate, notice, direction or other documentary confirmation purporting to have been issued by the investment manager or Investment Committee which the Trustee believes to be genuine and to have been issued by the investment manager or Investment Committee. The Trustee shall not be charged with knowledge of the termination of the appointment of any investment manager or Investment Committee until it receives written notice thereof from the Company.

- (d) Prior to a Change of Control, the Board of Directors of the Company may appoint an Investment Committee to direct the investment of the Fund. The Investment Committee may exercise any powers relating to the investment of Trust assets as described in Sections 6 and 7 hereof. The Investment Committee shall exercise its authority by an affirmative action of a majority of members constituting the Investment Committee, expressed from time to time by a vote at a meeting of the Investment Committee, or in an action in writing signed by all members without a meeting. Prior to a Change of Control, the Board of Directors of the Company shall have the right to remove and to replace any member of the Investment Committee at any time by notice in writing to that member. Following a Change of Control, the Company shall have no authority to remove or replace members of the Investment Committee, and any vacancy in the membership of the Investment Committee, created by resignation, disability, death or otherwise, shall be filled by the vote of a majority of the members of the Investment Committee then in office. Following a Change of Control, the Investment Committee may, on its own initiative, acquire fiduciary insurance for the benefit of its members at the Company's expense. If for any reason, the Company does not pay the premiums for such insurance, the Trustee shall pay such premiums out of the Trust assets and seek reimbursement from the Company.
- (e) Following a Change of Control, unless there is then in existence an Investment Committee as described in Section 6(d) above, the Trustee shall have the sole and absolute discretion in the management of the Trust assets and shall have all the powers set forth under Section 6(b). In investing the Trust assets, the Trustee shall consider:
 - (1) the needs of the Arrangements;
 - (2) the need for matching of the Trust assets with the liabilities of the Arrangements; and
 - (3) the duty of the Trustee to act solely in the best interests of the Participants and their Beneficiaries.
- (f) The Trustee shall have the right, in its sole discretion, to delegate its investment responsibility to an investment manager who may be an affiliate the Trustee. In the event the Trustee shall exercise this right, the Trustee shall remain, at all times responsible for the acts of an investment manager. The Trustee shall have the right to purchase an insurance policy or an annuity to fund the benefits of the Arrangements.
- (g) The Company shall have the right at any time, and from time to time in its sole discretion, to substitute assets of equal fair market value for any asset held by the Trust. This right is exercisable by the Company in a nonfiduciary capacity without the approval or consent of any person in a fiduciary capacity.

Section 7. Insurance Contracts

- (a) To the extent that the Trustee is directed by the Company prior to a Change of Control or by the Investment Committee after a Change of Control to invest part or all of the Trust Fund in insurance contracts, the type and amount thereof shall be specified by the Company. The Trustee shall be under no duty to make inquiry as to the propriety of the type or amount so specified.

- (b) Each insurance contract issued shall provide that the Trustee shall be the owner thereof with the power to exercise all rights, privileges, options and elections granted by or permitted under such contract or under the rules of the insurer. The exercise by the Trustee of any incidents of ownership under any contract shall, prior to a Change of Control, be subject to the direction of the Company. After a Change of Control, the Trustee shall have all such rights to the extent an Investment Committee had not been established.
- (c) The Trustee shall have no power to name a beneficiary of the policy other than the Trust, to assign the policy (as distinct from conversion of the policy to a different form) other than to a successor Trustee, or to loan to any person the proceeds of any borrowing against an insurance policy held in the Trust Fund.
- (d) No insurer shall be deemed to be a party to the Trust and an insurer's obligations shall be measured and determined solely by the terms of contracts and other agreements executed by the insurer.

Section 8. *Disposition of Income*

- (a) Prior to a Change of Control, all income received by the Trust, net of expenses and taxes, may be returned to the Company or accumulated and reinvested within the Trust at the direction of the Company. In addition, if, at any time prior to a Change of Control, the value of assets held in the Trust exceeds 100 percent of the amount necessary to pay each Participant or Beneficiary the benefits to which Participants or their Beneficiaries would be entitled pursuant to the terms of the Arrangements as of the date on which the determination is made, the Trustee shall return the excess to the Company at the Company's written request.
- (b) Following a Change of Control, all income received by the Trust, net of expenses and taxes, shall be accumulated and reinvested within the Trust.

Section 9. *Accounting by The Trustee*

The Trustee shall keep accurate and detailed records of all investments, receipts, disbursements, and all other transactions required to be made, including such specific records as shall be agreed upon in writing between the Company and the Trustee within forty-five (45) days following the close of each calendar year and within forty-five (45) days after the removal or resignation of the Trustee. The Trustee shall deliver to the Company a written account of its administration of the Trust during such year or during the period from the close of the last preceding year to the date of such removal or resignation setting forth all investments, receipts, disbursements and other transactions effected by it, including a description of all securities and investments purchased and sold with the cost or net proceeds of such purchases or sales (accrued interest paid or receivable being shown separately), and showing all cash, securities and other property held in the Trust at the end of such year or as of the date of such removal or resignation, as the case may be. The Company may approve such account by an instrument in writing delivered to the Trustee. In the absence of the Company's filing with the Trustee objections to any such account within ninety (90) days after its receipt, the Company shall be deemed to have so approved such account. In such case, or upon the written approval by the Company of any such account, the Trustee shall, to the extent permitted by law, be discharged from all liability to the Company for its acts or failures to act described by such account. The foregoing, however, shall not preclude the Trustee from having its accounting settled by a court of competent jurisdiction. The Trustee shall be entitled to hold and to commingle the assets of the Trust in one Fund for investment purposes but at the direction of the Company prior to a Change of Control, the Trustee shall create one or more sub-accounts.

Section 10. *Responsibility of The Trustee*

- (a) The Trustee shall act with the care, skill, prudence and diligence under the circumstances then prevailing that a prudent person acting in like capacity and familiar with such matters would use in the conduct of an enterprise of a like character and with like aims, provided, however, that the Trustee shall incur no liability to any person for any action taken pursuant to a direction, request or approval given by the Company which is contemplated by, and in conformity with, the terms of the Arrangements or this Trust and is given in writing by the Company. In the event of a dispute between the Company and a party, the Trustee may apply to a court of competent jurisdiction to resolve the dispute, subject, however to Section 2(d) hereof.
- (b) The Company hereby indemnifies the Trustee against losses, liabilities, claims, costs and expenses in connection with the administration of the Trust, unless resulting from the negligence or misconduct of Trustee. To the extent the Company fails to make any payment on account of an indemnity provided in this paragraph 10(b), in a reasonably timely manner, the Trustee may obtain payment from the Trust. If the Trustee undertakes or defends any litigation arising in connection with this Trust or to protect a Participant's or Beneficiary's rights under the Arrangements, the Company agrees to indemnify the Trustee against the Trustee's costs, reasonable expenses and liabilities (including, without limitation, attorneys' fees and expenses) relating thereto and to be primarily liable for such payments. If the Company does not pay such costs, expenses and liabilities in a reasonably timely manner, the Trustee may obtain payment from the Trust.
- (c) Prior to a Change of Control, the Trustee may consult with legal counsel (who may also be counsel for the Company generally) with respect to any of its duties or obligations hereunder. Following a Change of Control the Trustee shall select independent legal counsel and may consult with counsel or other persons with respect to its duties and with respect to the rights of Participants or their Beneficiaries under the Arrangements.
- (d) The Trustee may hire agents, accountants, actuaries, investment advisors, financial consultants or other professionals to assist it in performing any of its duties or obligations hereunder and may rely on any determinations made by such agents and information provided to it by the Company.
- (e) The Trustee shall have, without exclusion, all powers conferred on the Trustee by applicable law, unless expressly provided otherwise herein.
- (f) Notwithstanding any powers granted to the Trustee pursuant to this Trust Agreement or to applicable law, the Trustee shall not have any power that could give this Trust the objective of carrying on a business and dividing the gains therefrom, within the meaning of section 301.7701-2 of the Procedure and Administrative Regulations promulgated pursuant to the Internal Revenue Code.

Section 11. *Compensation and Expenses of The Trustee*

The Trustee's compensation shall be as agreed in writing from time to time by the Company and the Trustee. The Company shall pay all administrative expenses and the Trustee's fees and shall promptly reimburse the Trustee for any fees and expenses of its agents. If not so paid, the fees and expenses shall be paid from the Trust.

Section 12. *Resignation and Removal of The Trustee*

- (a) Prior to a Change of Control, the Trustee may resign at any time by written notice to the Company, which shall be effective sixty (60) days after receipt of such notice unless the Company and the Trustee agree otherwise. Following a Change of Control, the Trustee may resign only after the appointment of a successor Trustee.

- (b) The Trustee may be removed by the Company on sixty days (60) days notice or upon shorter notice accepted by the Trustee prior to a Change of Control. Subsequent to a Change of Control, the Trustee may only be removed by the Company with the consent of a majority of the Participants.
- (c) If the Trustee resigns within two years after a Change of Control, as defined herein, the Company, or if the Company fails to act within a reasonable period of time following such resignation, the Trustee shall apply to a court of competent jurisdiction for the appointment of a successor trustee or for instructions.
- (d) Upon resignation or removal of the Trustee and appointment of a successor Trustee, all assets shall subsequently be transferred to the successor Trustee. The transfer shall be completed within sixty (60) days after receipt of notice of resignation, removal or transfer, unless the Company extends the time limit.
- (e) If the Trustee resigns or is removed, a successor shall be appointed by the Company, in accordance with Section 13 hereof, by the effective date of resignation or removal under paragraph(s) (a) or (b) of this section. If no such appointment has been made, the Trustee may apply to a court of competent jurisdiction for appointment of a successor or for instructions. All expenses of the Trustee in connection with the proceeding shall be allowed as administrative expenses of the Trust.

Section 13. *Appointment of Successor*

- (a) If the Trustee resigns or is removed in accordance with Section 12 hereof, the Company may appoint, subject to Section 12, any third party national banking association with a market capitalization exceeding \$100,000,000 to replace the Trustee upon resignation or removal. The successor Trustee shall have all of the rights and powers of the former Trustee, including ownership rights in the Trust. The former Trustee shall execute any instrument necessary or reasonably requested by the Company or the successor Trustee to evidence the transfer.
- (b) The successor Trustee need not examine the records and acts of any prior Trustee and may retain or dispose of existing Trust assets, subject to Section 8 and 9 hereof. The successor Trustee shall not be responsible for and the Company shall indemnify and defend the successor Trustee from any claim or liability resulting from any action or inaction of any prior Trustee or from any other past event, or any condition existing at the time it becomes successor Trustee.

Section 14. *Amendment or Termination*

- (a) This Trust Agreement may be amended by a written instrument executed by the Trustee and the Company. Notwithstanding the foregoing, no such amendment shall conflict with the terms of the Arrangements or shall make the Trust revocable after it has become irrevocable in accordance with Section 1 hereof.
- (b) The Trust shall not terminate until the date on which Participants and their Beneficiaries have received all of the benefits due to them under the terms and conditions of the Arrangements. Upon termination of the Trust, the Trust assets shall be returned to the Company.
- (c) Upon written approval of all Participants or Beneficiaries entitled to payment of benefits pursuant to the terms of the Arrangements, the Company may terminate this Trust prior to the time all benefit payments under the Arrangements have been made. All assets in the Trust at termination shall be returned to the Company.
- (d) This Trust Agreement may not be amended or terminated by the Company for two (2) years following a Change of Control without the written consent of a majority of the Participants.

Section 15. *Change of Control*

(a) A "Change of Control" shall be deemed to have occurred if:

- (1) any "person" (as such term is used in Sections 13(d) and 14(d)(2) of the Securities Exchange Act of 1934, but excluding any benefit plan for employees or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the beneficial owner of securities of the Company representing twenty percent (20%) or more of the combined voting power of the Company's then outstanding securities;
- (2) during any two consecutive years, individuals who at the beginning of such a period constitute the Board of Directors of the Company cease for any reason to constitute at least a majority of the Board of Directors of the Company, unless the election, or the nomination for election by the shareholders of the Company, of each new Director was approved by a vote of at least two-thirds ($\frac{2}{3}$) of the Directors then still in office who were Directors at the beginning of the period; or
- (3) the Company has executed and delivered a definitive agreement which would require the consummation of (i) any consolidation or merger of the Company in which the Company is not the continuing or surviving corporation or pursuant to which shares of common stock are converted into cash, securities or other property, other than a merger of the Company in which the holders of the common stock immediately prior to the merger have the same proportionate ownership of common stock of the surviving corporation immediately after the merger, (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Company, or (iii) any plan or proposal for the liquidation or dissolution of the Company.
- (4) the shareholders of the Company shall have approved (i) any consolidation or merger of the Company in which the Company is not the continuing or surviving corporation or pursuant to which shares of common stock are converted into cash, securities or other property, other than a merger of the Company in which the holders of the common stock immediately prior to the merger have the same proportionate ownership of common stock of the surviving corporation immediately after the merger, (ii) any sale, lease, exchange or other transfer (in one transaction or a series of related transactions) of all or substantially all of the assets of the Company, or (iii) any plan or proposal for the liquidation or dissolution of the Company.

Notwithstanding the foregoing, the phrase "Change of Control" shall not apply to any reorganization or merger initiated voluntarily by the Company in which the Company is the continuing surviving entity.

For purposes of this Section 15(a), the Board of Directors of the Company, by a majority vote, shall have the power to determine on the basis of information known to them (a) the number of shares beneficially owned by any person, entity or group; (b) whether there exists an agreement, arrangement or understanding with another as to matters referred to in this Section 15(a); and (c) such other matters with respect to which a determination is necessary under this Section 15(a).

- (b) The General Counsel of the Company shall have the specific authority to determine whether a Change of Control has transpired under the guidance of this Section 15(a) and shall be required to give the Trustee notice of a Change of Control. The Trustee shall be entitled to rely upon such notice, but if the Trustee receives notice of a Change of Control from another source, the Trustee shall make its own independent determination.

Section 16. Miscellaneous

- (a) Any provision of this Trust Agreement prohibited by law shall be ineffective to the extent of any such prohibition, without invalidating the remaining provisions hereof.
- (b) The Company hereby represents and warrants that all of the Arrangements have been established, maintained and administered in accordance with all applicable laws, including without limitation, ERISA. The Company hereby indemnifies and agrees to hold the Trustee harmless from all liabilities, including attorney's fees, relating to or arising out of the establishment, maintenance and administration of the Arrangements. To the extent the Company does not pay any of such liabilities in a reasonably timely manner, the Trustee may obtain payment from the Trust.
- (c) Benefits payable to Participants and their Beneficiaries under this Trust Agreement may not be anticipated, assigned (either at law or in equity), alienated, pledged, encumbered or subjected to attachment, garnishment, levy, execution or other legal or equitable process.
- (d) This Trust Agreement shall be governed by and construed in accordance with the laws of North Carolina.

IN WITNESS WHEREOF , this Grantor Trust Agreement has been executed on behalf of the parties hereto on the day and year first above written.

PG&E CORPORATION

By: Bruce R. Worthington

Name: Bruce R. Worthington
Its: Senior Vice President and General Counsel
Chairperson, Employee Benefit Committee

ATTEST:

By: Linda Y.H. Cheng

 Linda Y.H. Cheng
Its: Assistant Corporate Secretary

WACHOVIA BANK, N.A.

By: Joe O. Long

Name: Joe O. Long
Its: Senior Vice President

ATTEST:

By: John N. Smith

 John N. Smith
Its: Assistant Secretary

Attachment I

**PG&E CORPORATION OFFICER GRANTOR TRUST AGREEMENT
NONQUALIFIED BENEFIT PLANS COVERED**

- Pacific Gas and Electric Company Supplemental Executive Retirement Plan (SERP)
 - Pacific Gas and Electric Company Retirement Excess Benefit Plan
 - PG&E Corporation Deferred Compensation Plan for Officers
 - PG&E Corporation Supplemental Executive Retirement Plan (SERP)
-

PG&E CORPORATION OFFICER GRANTOR TRUST AGREEMENT

Attachment I

PG&E CORPORATION OFFICER GRANTOR TRUST AGREEMENT NONQUALIFIED BENEFIT PLANS COVERED

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Exhibit 10.40

Indemnification

**RESOLUTION OF THE
BOARD OF DIRECTORS OF
PG&E CORPORATION**

December 18, 1996

WHEREAS, the Articles of Incorporation of this corporation permit indemnification of corporate agents in excess of the indemnification provisions of Section 317 of the California Corporations Code;

NOW, THEREFORE, BE IT RESOLVED THAT:

1. *Indemnification of Directors and Officers*

Each person who was or is a party or is threatened to be made a party to, or who is involved in any threatened, pending, or completed action, suit, or proceeding, formal or informal, whether brought in the name of this corporation (the "Corporation") or otherwise, and whether of a civil, criminal, administrative, or investigative nature (hereinafter a "proceeding"), by reason of the fact that he or she, or a person of whom he or she is the legal representative, is or was a director or officer of the Corporation, or is or was a director or officer of the Corporation serving at the request of the Corporation (as determined by a committee composed of the General Counsel and the Corporate Secretary) as a director, officer, employee, or agent of another corporation or of a partnership, joint venture, trust, or other enterprise, including service with respect to employee benefit plans, whether the basis of such proceeding is an alleged action or inaction in an official capacity or in any other capacity while serving as a director or officer, shall, subject to the terms of any agreement between the Corporation and such a person, be indemnified and held harmless by the Corporation to the fullest extent permissible under California law and the Corporation's Articles of Incorporation, against all costs, charges, expenses, liabilities, and losses (including, without limitation, attorneys' fees, judgments, fines, ERISA excise taxes, or penalties and amounts paid or to be paid in settlement) reasonably incurred or suffered by such person in connection therewith, and such indemnification shall continue as to a person who has ceased to be a director or officer and shall inure to the benefit of his or her heirs, executors, and administrators; provided, however, that (a) the Corporation shall indemnify any such person seeking indemnification in connection with a proceeding (or part thereof) initiated by such person only if such proceeding (or part thereof) was authorized by the Board of the Corporation, (b) the Corporation shall indemnify any such person seeking indemnification in connection with a proceeding (hereinafter a "third party proceeding") (or part thereof) other than a proceeding by or in the name of the Corporation to procure a judgment in its favor (hereinafter a "derivative proceeding") only if any settlement of such a proceeding is approved in writing by the Corporation, and (c) no such person shall be indemnified:

- (i) Except to the extent that the aggregate of losses to be indemnified exceeds the amount of such losses for which the director or officer is paid pursuant to any directors' or officers' liability insurance policy maintained by the Corporation;
 - (ii) On account of any suit on which judgment is rendered against such person for an accounting of profits made from the purchase or sale by such person of securities of the Corporation pursuant to the provisions of Section 16(b) of the Securities Exchange Act of 1934 and amendments thereto;
 - (iii) If a court of competent jurisdiction finally determines that any indemnification hereunder is unlawful;
 - (iv) For acts or omissions involving intentional misconduct or knowing and culpable violation of law;
-

- (v) For acts or omissions that the director or officer believes to be contrary to the best interests of the Corporation or its shareholders, or that involve the absence of good faith on the part of the director or officer;
- (vi) For any transaction from which the director or officer derived an improper personal benefit;
- (vii) For acts or omissions that show a reckless disregard for the director's or officer's duty to the Corporation or its shareholders in circumstances in which the director or officer was aware, or should have been aware, in the ordinary course of performing his or her duties, of a risk of serious injury to the Corporation or its shareholders;
- (viii) For acts or omissions that constitute an unexcused pattern of inattention that amount to an abdication of the director's or officer's duties to the Corporation or its shareholders;
- (ix) For costs, charges, expenses, liabilities, and losses arising under Section 310 or 316 of the California Corporations Code (the "Code"); or
- (x) As to circumstances in which indemnity is expressly prohibited by Section 317 of the Code;

provided, however, that the exclusions set forth in clauses (iv) through (x) above shall apply only to indemnification for acts, omissions, or transactions involving breach of duty to the Corporation and its shareholders. The General Counsel or the Board of Directors of the Corporation shall make the determination as to whether any of the exclusions set forth in clauses (iv) through (x) above applies in a particular case;

2. Indemnification as a Contract Right

The indemnification rights set forth in this resolution with respect to directors and officers of the Corporation shall be a contract right and shall include the right to be paid by the Corporation expenses actually and reasonably incurred in defending any proceeding in advance of its final disposition; provided that such advances be conditioned upon delivery to the Corporation of an undertaking, by or on behalf of the director or officer, to repay all amounts to the Corporation if it shall be ultimately determined that such person is not entitled to be indemnified;

3. Indemnification of Employees and Agents

A person who was or is a party or is threatened to be made a party to or is involved in any proceeding by reason of the fact that he or she is or was an employee or agent of the Corporation (other than a director or officer) or is or was serving at the request of the Corporation as an employee or agent of another enterprise, including service with respect to employee benefit plans, whether the basis of such proceeding is an alleged action or inaction while serving as an employee or agent, may, subject to the terms of any agreement between the Corporation and such person, be indemnified and held harmless by the Corporation to the fullest extent permissible under California law and the Corporation's Articles of Incorporation, against all costs, charges, expenses, liabilities, and losses (including, without limitation, attorneys' fees, judgments, fines, ERISA excise taxes, or penalties and amounts paid or to be paid in settlement), reasonably and actually incurred or suffered by such person in connection therewith (hereinafter "indemnifiable losses"). The immediately preceding sentence is not intended to be and shall not be considered to confer a contract right on any employee or agent (other than directors and officers) of the Corporation.

The Corporation may also advance to an employee or agent referenced in this paragraph expenses reasonably and actually incurred or suffered in defending any proceeding, or may agree to provide prospective indemnification of any such person against indemnifiable losses in any third party proceeding prior to the final disposition of such proceeding; provided, however, that (a) the Corporation may make such advances in any proceeding or agree to provide such indemnification to any such employee or agent in any third party proceeding prior to the final disposition of such proceeding only if an investigation is conducted with respect to the circumstances of the conduct at

issue and it is determined by a committee composed of the President, the General Counsel, and the Chief Financial Officer or by any person designated by such committee, based on the results of such investigation, that such person is entitled to indemnification because he or she is or was involved in such proceeding, or is threatened to be involved in such proceeding, as a direct consequence of (i) the discharge of such person's duties as an employee or agent of the Corporation, or (ii) such person's obedience to the directions of the Corporation, even though unlawful, unless such person, at the time of obeying such directions, believed them to be unlawful, (b) notwithstanding any determination by such committee or its designee that any such employee or agent is entitled to any advance or indemnification pursuant to clause (a) above, the Corporation shall have the right to discontinue any advance to such person and to terminate any oral or written agreement to provide prospective indemnification to such person in the event that it is subsequently determined by the committee or its designee that such person is not entitled to be indemnified under California law, and (c) any advance to any such employee or agent shall be conditioned upon delivery to the Corporation of an undertaking, by or on behalf of such person, to repay all amounts to the Corporation if it shall ultimately be determined that such person is not entitled to be indemnified;

4. Right of Directors and Officers to Bring Suit

If a claim by a director or officer under this resolution is not paid in full by the Corporation within 90 days after a written claim has been received by the Corporation, the claimant may at any time thereafter bring suit against the Corporation to recover the unpaid amount of the claim and, if successful in whole or in part, the claimant shall also be entitled to be paid the expense of prosecuting the claim. Neither the failure of the Corporation (including its Board, independent legal counsel, or its shareholders) to have made a determination prior to the commencement of such action that indemnification of the claimant is permissible in the circumstances because he or she has met the applicable standard of conduct, if any, nor an actual determination by the Corporation before the commencement of such action that the claimant had not met any applicable standard of conduct, shall be a defense to the action or create a presumption for the purpose of an action that the claimant has not met the applicable standard of conduct;

5. Non-Exclusivity of Rights

The right to indemnification provided by this resolution shall not be exclusive of any other right which any person may have or hereafter acquire under any statute, bylaw, agreement, vote of shareholders or disinterested directors, or otherwise;

6. Expenses as a Witness

To the extent that any director, officer, employee, or agent of the Corporation is by reason of such position, or position with another entity at the request of the Corporation, a witness in any action, suit, or proceeding, he or she shall be indemnified against all costs and expenses actually and reasonably incurred by him or her on his or her behalf in connection therewith;

7. Indemnity Agreements

The Corporation may enter into agreements with any director, officer, employee, or agent of the Corporation providing for indemnification to the fullest extent permissible under California law and the Corporation's Articles of Incorporation;

8. Separability

Each and every paragraph, sentence, term, and provision of this resolution is separate and distinct, so that if any paragraph, sentence, term, or provision hereof shall be held to be invalid or unenforceable for any reason, such invalidity or unenforceability shall not affect the validity or enforceability of any other paragraph, sentence, term, or provision hereof. To the extent required, any paragraph, sentence, term, or provision of this resolution may be modified by a court of competent jurisdiction to preserve its validity and to provide the claimant with, subject to the limitations set forth

in this resolution and any agreement between the Corporation and claimant, the broadest indemnification permitted under applicable law;

BE IT FURTHER RESOLVED that this resolution shall apply to all proceedings based on any action or omission occurring on or after November 17, 1995; and

BE IT FURTHER RESOLVED that any repeal or amendment of this resolution shall have prospective effect only, and shall not adversely affect any rights of indemnification of a director or officer existing at the time of such repeal or amendment with respect to any action or omission occurring prior to such repeal or amendment, and, further, shall not apply to any proceeding, irrespective of when the proceeding is initiated, arising from the service of such director or officer which occurred prior to such repeal or amendment.

I, LINDA Y.H. CHENG, do hereby certify that I am Vice President and Corporate Secretary of PG&E CORPORATION, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held at the office of said corporation on December 18, 1996; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 26th day of January, 2005.

/s/ LINDA Y.H. CHENG

Linda Y.H. Cheng
Vice President and Corporate Secretary
PG&E CORPORATION

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S E A L

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Indemnification

**RESOLUTION OF THE
BOARD OF DIRECTORS OF
PACIFIC GAS AND ELECTRIC COMPANY**

July 19, 1995

WHEREAS, the Board of Directors of this corporation previously has adopted, and the shareholders of the corporation previously have approved, an amendment to the Articles of Incorporation to permit indemnification of corporate agents in excess of the indemnification provisions of Section 317 of the California Corporations Code; and

WHEREAS, the above-mentioned amendment to the Articles was filed with the California Secretary of State's office on April 22, 1988; and

WHEREAS, on May 18, 1988, the Board of Directors adopted a resolution implementing the authority provided by the above-mentioned amendment to the Articles; and

WHEREAS, it is desirable and in the best interests of the corporation and its shareholders to amend the May 18, 1988, resolution to expand the indemnification of corporate agents;

NOW, THEREFORE, BE IT RESOLVED THAT:

1. *Indemnification of Directors and Officers*

Each person who was or is a party or is threatened to be made a party to, or who is involved in any threatened, pending or completed action, suit or proceeding, formal or informal, whether brought in the name of this corporation (the "Corporation") or otherwise, and whether of a civil, criminal, administrative or investigative nature (hereinafter a "proceeding"), by reason of the fact that he or she, or a person of whom he or she is the legal representative, is or was a director or officer of the Corporation, or is or was a director or officer of the Corporation serving at the request of the Corporation (as determined by a committee composed of the General Counsel and the Corporate Secretary) as a director, officer, employee or agent of another corporation or of a partnership, joint venture, trust or other enterprise, including service with respect to employee benefit plans, whether the basis of such proceeding is an alleged action or inaction in an official capacity or in any other capacity while serving as a director or officer, shall, subject to the terms of any agreement between the Corporation and such a person, be indemnified and held harmless by the Corporation to the fullest extent permissible under California law and the Corporation's Articles of Incorporation, against all costs, charges, expenses, liabilities and losses (including, without limitation, attorneys' fees, judgments, fines, ERISA excise taxes, or penalties and amounts paid or to be paid in settlement) reasonably incurred or suffered by such person in connection therewith, and such indemnification shall continue as to a person who has ceased to be a director or officer and shall inure to the benefit of his or her heirs, executors and administrators; provided, however, that (a) the Corporation shall indemnify any such person seeking indemnification in connection with a proceeding (or part thereof) initiated by such person only if such proceeding (or part thereof) was authorized by the Board of the Corporation, (b) the Corporation shall indemnify any such person seeking indemnification in connection with a proceeding (hereinafter a "third party proceeding") (or part thereof) other than a proceeding by or in the name of the Corporation to procure a judgment in its favor (hereinafter a "derivative proceeding") only if any settlement of such a proceeding is approved in writing by the Corporation, and (c) no such person shall be indemnified:

- (i) Except to the extent that the aggregate of losses to be indemnified exceeds the amount of such losses for which the director or officer is paid pursuant to any directors' or officers' liability insurance policy maintained by the Corporation;

- (ii) On account of any suit on which judgment is rendered against such person for an accounting of profits made from the purchase or sale by such person of securities of the Corporation pursuant to the provisions of Section 16(b) of the Securities Exchange Act of 1934 and amendments thereto;
- (iii) If a court of competent jurisdiction finally determines that any indemnification hereunder is unlawful;
- (iv) For acts or omissions involving intentional misconduct or knowing and culpable violation of law;
- (v) For acts or omissions that the director or officer believes to be contrary to the best interests of the Corporation or its shareholders, or that involve the absence of good faith on the part of the director or officer;
- (vi) For any transaction from which the director or officer derived an improper personal benefit;
- (vii) For acts or omissions that show a reckless disregard for the director's or officer's duty to the Corporation or its shareholders in circumstances in which the director or officer was aware, or should have been aware, in the ordinary course of performing his or her duties, of a risk of serious injury to the Corporation or its shareholders;
- (viii) For acts or omissions that constitute an unexcused pattern of inattention that amount to an abdication of the director's or officer's duties to the Corporation or its shareholders;
- (ix) For costs, charges, expenses, liabilities and losses arising under Section 310 or 316 of the California Corporations Code (the "Code"); or
- (x) As to circumstances in which indemnity is expressly prohibited by Section 317 of the Code;

provided, however, that the exclusions set forth in clauses (iv) through (x) above shall apply only to indemnification for acts, omissions or transactions involving breach of duty to the Corporation and its shareholders. The General Counsel or the Board of Directors of the Corporation shall make the determination as to whether any of the exclusions set forth in clauses (iv) through (x) above applies in a particular case;

2. *Indemnification as a Contract Right*

The indemnification rights set forth in this resolution with respect to directors and officers of the Corporation shall be a contract right and shall include the right to be paid by the Corporation expenses actually and reasonably incurred in defending any proceeding in advance of its final disposition; provided that such advances be conditioned upon delivery to the Corporation of an undertaking, by or on behalf of the director or officer, to repay all amounts to the Corporation if it shall be ultimately determined that such person is not entitled to be indemnified;

3. *Indemnification of Employees and Agents*

A person who was or is a party or is threatened to be made a party to or is involved in any proceeding by reason of the fact that he or she is or was an employee or agent of the Corporation (other than a director or officer) or is or was serving at the request of the Corporation as an employee or agent of another enterprise, including service with respect to employee benefit plans, whether the basis of such proceeding is an alleged action or inaction while serving as an employee or agent, may, subject to the terms of any agreement between the Corporation and such person, be indemnified and held harmless by the Corporation to the fullest extent permissible under California law and the Corporation's Articles of Incorporation, against all costs, charges, expenses, liabilities, and losses (including, without limitation, attorneys' fees, judgments, fines, ERISA excise taxes, or penalties and amounts paid or to be paid in settlement), reasonably and actually incurred or suffered by such person in connection therewith (hereinafter "indemnifiable losses"). The immediately preceding sentence is not

intended to be and shall not be considered to confer a contract right on any employee or agent (other than directors and officers) of the Corporation.

The Corporation may also advance to an employee or agent referenced in this paragraph expenses reasonably and actually incurred or suffered in defending any proceeding, or may agree to provide prospective indemnification of any such person against indemnifiable losses in any third party proceeding prior to the final disposition of such proceeding; provided, however, that (a) the Corporation may make such advances in any proceeding or agree to provide such indemnification to any such employee or agent in any third party proceeding prior to the final disposition of such proceeding only if an investigation is conducted with respect to the circumstances of the conduct at issue and it is determined by a committee composed of the General Counsel, the Vice President—Human Resources and the officer in charge of such person's business unit or corporate services department, or by any person designated by such committee, based on the results of such investigation, that such person is entitled to indemnification because he or she is or was involved in such proceeding, or is threatened to be involved in such proceeding, as a direct consequence of (i) the discharge of such person's duties as an employee or agent of the Corporation, or (ii) such person's obedience to the directions of the Corporation, even though unlawful, unless such person, at the time of obeying such directions, believed them to be unlawful, (b) notwithstanding any determination by such committee or its designee that any such employee or agent is entitled to any advance or indemnification pursuant to clause (a) above, the Corporation shall have the right to discontinue any advance to such person and to terminate any oral or written agreement to provide prospective indemnification to such person in the event that it is subsequently determined by the committee or its designee that such person is not entitled to be indemnified under California law, and (c) any advance to any such employee or agent shall be conditioned upon delivery to the Corporation of an undertaking, by or on behalf of such person, to repay all amounts to the Corporation if it shall ultimately be determined that such person is not entitled to be indemnified;

4. Right of Directors and Officers to Bring Suit

If a claim by a director or officer under this resolution is not paid in full by the Corporation within 90 days after a written claim has been received by the Corporation, the claimant may at any time thereafter bring suit against the Corporation to recover the unpaid amount of the claim and, if successful in whole or in part, the claimant shall also be entitled to be paid the expense of prosecuting the claim. Neither the failure of the Corporation (including its Board, independent legal counsel, or its shareholders) to have made a determination prior to the commencement of such action that indemnification of the claimant is permissible in the circumstances because he or she has met the applicable standard of conduct, if any, nor an actual determination by the Corporation before the commencement of such action that the claimant had not met any applicable standard of conduct, shall be a defense to the action or create a presumption for the purpose of an action that the claimant has not met the applicable standard of conduct;

5. Non-Exclusivity of Rights

The right to indemnification provided by this resolution shall not be exclusive of any other right which any person may have or hereafter acquire under any statute, bylaw, agreement, vote of shareholders or disinterested directors or otherwise;

6. Expenses as a Witness

To the extent that any director, officer, employee or agent of the Corporation is by reason of such position, or position with another entity at the request of the Corporation, a witness in any action, suit or proceeding, he or she shall be indemnified against all costs and expenses actually and reasonably incurred by him or her on his or her behalf in connection therewith;

7. *Indemnity Agreements*

The Corporation may enter into agreements with any director, officer, employee or agent of the Corporation providing for indemnification to the fullest extent permissible under California law and the Corporation's Articles of Incorporation;

8. *Separability*

Each and every paragraph, sentence, term and provision of this resolution is separate and distinct, so that if any paragraph, sentence, term or provision hereof shall be held to be invalid or unenforceable for any reason, such invalidity or unenforceability shall not affect the validity or unenforceability of any other paragraph, sentence, term or provision hereof. To the extent required, any paragraph, sentence, term or provision of this resolution may be modified by a court of competent jurisdiction to preserve its validity and to provide the claimant with, subject to the limitations set forth in this resolution and any agreement between the Corporation and claimant, the broadest indemnification permitted under applicable law;

BE IT FURTHER RESOLVED that this resolution shall apply to all proceedings based on any action or omission occurring on or after May 18, 1988;

BE IT FURTHER RESOLVED that any repeal or amendment of this resolution shall have prospective effect only, and shall not adversely affect any rights of indemnification of a director or officer existing at the time of such repeal or amendment with respect to any action or omission occurring prior to such repeal or amendment, and, further, shall not apply to any proceeding, irrespective of when the proceeding is initiated, arising from the service of such director or officer which occurred prior to such repeal or amendment;

BE IT FURTHER RESOLVED that the resolutions on this subject adopted by the Board of Directors on February 19, 1986, and May 18, 1988, are hereby superseded, with the exception that indemnification relating to any proceeding based upon acts or omissions occurring prior to May 18, 1988, shall be governed by the resolution of February 19, 1986.

I, LINDA Y.H. CHENG, do hereby certify that I am Vice President and Corporate Secretary of PACIFIC GAS AND ELECTRIC COMPANY, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held at the office of said corporation on July 19, 1995; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 26th day of January, 2005.

/s/ LINDA Y.H. CHENG

Linda Y.H. Cheng
Vice President and Corporate Secretary
PACIFIC GAS AND ELECTRIC COMPANY

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EXHIBIT 11

PG&E CORPORATION
COMPUTATION OF EARNINGS (LOSS) PER COMMON SHARE

	Year Ended December 31,		
	2004	2003	2002 ⁽¹⁾
	(in millions, except per share amounts)		
Income from continuing operations	\$ 3,820	\$ 791	\$ 1,723
Discontinued operations	684	(365)	(2,536)
Net income (loss) before cumulative effect of changes in accounting principles	4,504	426	(813)
Cumulative effect of changes in accounting principles	—	(6)	(61)
Net income (loss) for basic and diluted calculations	4,504	420	(874)
Earnings (loss) allocated to common shareholders, basic	4,299	400	(853)
Earnings (loss) allocated to 9.50% Convertible Subordinated Notes, basic	205	20	(21)
	4,504	420	(874)
Earnings (loss) allocated to common shareholders, diluted	4,303	401	(853)
Earnings (loss) allocated to 9.50% Convertible Subordinated Notes, diluted	201	19	(21)
	4,504	420	(874)
Weighted average common shares outstanding, basic ⁽²⁾	398	385	371
9.50% Convertible Subordinated Notes	19	19	9
Weighted average common shares and participating securities, basic	417	404	380
Employee stock options, restricted stock, PG&E Corporation shares held by grantor trusts and accelerated share repurchase agreement ⁽³⁾	7	4	2
PG&E Corporation Warrants	2	5	2
Weighted average common shares outstanding and participating securities, diluted	426	413	384
Earnings (Loss) Per Common Share, Basic			
Income from continuing operations	\$ 9.16	\$ 1.96	\$ 4.53
Discontinued operations	1.64	(0.90)	(6.67)
Cumulative effect of changes in accounting principles	—	(0.01)	(0.16)
Rounding	—	(0.01)	—
Net earnings (loss) per common share, basic	\$ 10.80	\$ 1.04	\$ (2.30)
Earnings (Loss) Per Common Share, Diluted			
Income from continuing operations	\$ 8.97	\$ 1.92	\$ 4.49
Discontinued operations	1.60	(0.88)	(6.60)
Cumulative effect of changes in accounting principles	—	(0.01)	(0.16)
Rounding	—	(0.01)	—

Net earnings (loss) per common share, diluted	\$	10.57	\$	1.02	\$	(2.27)

-
- (1)

Prior period amounts of NEGT, Inc. have been reclassified to discontinued operations.
- (2)

Weighted average common shares outstanding exclude shares held by a subsidiary of PG&E Corporation (24,665,500 at December 31, 2004 and 23,815,500 shares at December 31, 2003 and 2002) and PG&E Corporation shares held by grantor trusts to secure deferred compensation obligations (281,985 shares at December 31, 2004, 2003 and 2002).
- (3)

Includes approximately 222,000 shares of PG&E Corporation common stock potentially issuable in settlement of an obligation of PG&E Corporation of approximately \$7.4 million under an accelerated share repurchase agreement at December 31, 2004.

EXHIBIT 11

PG&E CORPORATION COMPUTATION OF EARNINGS (LOSS) PER COMMON SHARE

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EXHIBIT 12.1

**PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

	Year ended December 31,				
	2004	2003	2002	2001	2000
(in millions)					
Earnings:					
Net income (loss)	\$ 3,982	\$ 923	\$ 1,819	\$ 1,015	\$ (3,483)
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	—	—	—	—	—
Income taxes provision (benefit)	2,561	528	1,178	596	(2,154)
Net fixed charges	671	964	1,029	1,019	648
Total Earnings (Loss)	\$ 7,214	\$ 2,415	\$ 4,026	\$ 2,630	\$ (4,989)
Fixed Charges:					
Interest on short-term borrowings and long-term debt, net	\$ 682	\$ 947	\$ 996	\$ 981	\$ 616
Interest on capital leases	1	1	2	2	2
AFUDC debt	(12)	16	21	12	6
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	—	—	10	24	24
Total Fixed Charges	\$ 671	\$ 964	\$ 1,029	\$ 1,019	\$ 648
Ratios of Earnings (Loss) to Fixed Charges	10.75	2.51	3.91	2.58	(7.70) ⁽¹⁾

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust.

⁽¹⁾ The ratio of earnings to fixed charges indicates a deficiency of less than one-to-one coverage aggregating \$5,637 million for the year ended December 31, 2000.

EXHIBIT 12.1

PACIFIC GAS AND ELECTRIC COMPANY COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

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EXHIBIT 12.2

**PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO COMBINED
FIXED CHARGES AND PREFERRED STOCK DIVIDENDS**

	Year ended December 31,				
	2004	2003	2002	2001	2000
(in millions)					
Earnings:					
Net income (loss)	\$ 3,982	\$ 923	\$ 1,819	\$ 1,015	\$ (3,483)
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	—	—	—	—	—
Income taxes provision (benefit)	2,561	528	1,178	596	(2,154)
Net fixed charges	671	964	1,029	1,019	648
Total Earnings (Loss)	\$ 7,214	\$ 2,415	\$ 4,026	\$ 2,630	\$ (4,989)
Fixed Charges:					
Interest on short-term borrowings and long-term debt, net	\$ 682	\$ 947	\$ 996	\$ 981	\$ 616
Interest on capital leases	1	1	2	2	2
AFUDC debt	(12)	16	21	12	6
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	—	—	10	24	24
Total Fixed Charges	671	964	1,029	1,019	648
Preferred Stock Dividends:					
Tax deductible dividends	9	9	9	9	9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	34	27	28	27	27
Total Preferred Stock Dividends	43	36	37	36	36
Total Combined Fixed Charges and Preferred Stock Dividends	\$ 714	\$ 1,000	\$ 1,066	\$ 1,055	\$ 684
Ratios of Earnings (Loss) to Combined Fixed Charges and Preferred Stock Dividends	10.10	2.42	3.78	2.49	(7.29) ⁽¹⁾

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on

long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the non-tax deductible dividends on outstanding preferred securities.

- (1) The ratio of earnings to combined fixed charges and preferred stock dividends indicates a deficiency of less than one-to-one coverage aggregating \$5,673 million for the year ended December 31, 2000.
-

EXHIBIT 12.2

PACIFIC GAS AND ELECTRIC COMPANY COMPUTATION OF RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

[QuickLinks](#) -- Click here to rapidly navigate through this document

Exhibit 13

SELECTED FINANCIAL DATA

	2004	2003	2002	2001	2000
	(in millions, except per share amounts)				
PG&E Corporation ⁽¹⁾					
For the Year					
Operating revenues	\$ 11,080	\$ 10,435	\$ 10,505	\$ 10,450	\$ 9,623
Operating income (loss)	7,118	2,343	3,954	2,613	(5,077)
Income (loss) from continuing operations	3,820	791	1,723	1,021	(3,435)
Earnings (loss) per common share from continuing operations, basic	9.16	1.96	4.53	2.81	(9.49)
Earnings (loss) per common share from continuing operations, diluted	8.97	1.92	4.49	2.80	(9.49)
Dividends declared per common share	—	—	—	—	1.20
At Year-End					
Book value per common share ⁽²⁾	\$ 20.90	\$ 10.16	\$ 8.92	\$ 11.91	\$ 8.76
Common stock price per share	33.28	27.77	13.90	19.24	20.00
Total assets	34,540	30,175	36,081	38,529	38,786
Long-term debt (excluding current portion)	7,323	3,314	3,715	3,923	3,346
Rate reduction bonds (excluding current portion)	580	870	1,160	1,450	1,740
Financial debt subject to compromise	—	5,603	5,605	5,651	—
Preferred stock of subsidiary with mandatory redemption provisions	122	137	137	137	137
Pacific Gas and Electric Company ⁽¹⁾					
For the Year					
Operating revenues	\$ 11,080	\$ 10,438	\$ 10,514	\$ 10,462	\$ 9,637
Operating income (loss)	7,144	2,339	3,913	2,478	(5,201)
Income available for (loss allocated to) common stock	3,961	901	1,794	990	(3,508)
At Year-End					
Total assets	\$ 34,302	\$ 29,066	\$ 27,593	\$ 28,105	\$ 24,622
Long-term debt (excluding current portion)	7,043	2,431	2,739	3,019	3,342
Rate reduction bonds (excluding current portion)	580	870	1,160	1,450	1,740
Financial debt subject to compromise	—	5,603	5,605	5,651	—
Preferred stock with mandatory redemption provisions	122	137	137	137	137

⁽¹⁾ Operating income (loss) and income (loss) from continuing operations reflect the write-off of generation-related regulatory assets and under-collected electricity purchase costs in 2000 and the recognition of regulatory assets in 2004 provided under the December 19, 2003 settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC to resolve the Utility's Chapter 11 proceeding. Matters relating to certain data, including discontinued operations, and the cumulative effect of changes in accounting principles, are discussed in Management's Discussion and Analysis and in the Notes to the Consolidated Financial Statements.

⁽²⁾ Book value per common shares includes the effect of participating securities. The dilutive effect of outstanding stock options and restricted stock are further disclosed in the Notes to the Consolidated Financial Statements.



MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation, incorporated in California in 1995, is an energy-based holding company that conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages primarily in the businesses of electricity and natural gas distribution, electricity generation, procurement and transmission, and natural gas procurement, transportation and storage. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation. Both PG&E Corporation and the Utility are headquartered in San Francisco, California. Through October 29, 2004, PG&E Corporation also owned National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, Inc., which engaged in electricity generation and natural gas transportation in the United States, or U.S., and which is accounted for as discontinued operations.

This is a combined annual report of PG&E Corporation and the Utility and includes separate Consolidated Financial Statements for each of these two entities. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations, or MD&A, should be read in conjunction with the Consolidated Financial Statements and Notes to the Consolidated Financial Statements included in this annual report.

The Utility served approximately 4.9 million electricity distribution customers and approximately 4.1 million natural gas distribution customers at December 31, 2004. The Utility had approximately \$34.3 billion in assets at December 31, 2004 and generated revenues of approximately \$11.1 billion in 2004. Its revenues are generated mainly through the sale and delivery of electricity and natural gas.

The Utility is regulated primarily by the California Public Utilities Commission, or the CPUC, and the Federal Energy Regulatory Commission, or the FERC. The CPUC has jurisdiction to set the rates, terms and conditions of service for the Utility's electricity distribution, natural gas distribution and natural gas transportation and storage services in California, among other matters. The CPUC is also responsible for setting service levels and certain operating practices and for reviewing the Utility's capital and operating costs. In certain cases, the CPUC prescribes specific accounting treatment for capital and operating costs. The FERC has jurisdiction to set the rates, terms and conditions of service for the Utility's electricity transmission operations and wholesale electricity sales.

CPUC and FERC decisions have a significant impact on the amount of operating and capital costs the Utility incurs and the amount the Utility is authorized to recover from customers for these costs through the authorization of "revenue requirements." Revenue requirements are designed to allow the Utility an opportunity to recover its reasonable costs of providing utility services, including a return of, and a fair rate of return on, its investment in utility facilities, or rate base.

Factors Affecting 2004 Results of Operation and Financial Condition

During 2004, several events had a significant impact on PG&E Corporation's and the Utility's results of operation and financial condition, including:

- The Utility's reorganization under Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, on April 12, 2004, the effective date of its plan of reorganization, and the associated \$7.8 billion exit financing;

- The return to cost-of-service ratemaking for the Utility's electricity distribution and generation operations;
- The CPUC's authorization of a majority of the Utility's base revenue requirements in the Utility's 2003 General Rate Case, or GRC; and
- The elimination of PG&E Corporation's equity ownership in NEGT.

The Utility's Plan of Reorganization and Settlement Agreement

The Utility's plan of reorganization under Chapter 11 became effective on April 12, 2004, or the Effective Date. The plan of reorganization incorporated the terms of the settlement agreement approved by the CPUC on December 18, 2003, and entered into among the CPUC, the Utility and PG&E Corporation on December 19, 2003, to resolve the Utility's Chapter 11 proceeding, or the Settlement Agreement. At March 31, 2004, the Utility recorded approximately \$4.9 billion of regulatory assets established under the Settlement Agreement (including a \$2.2 billion, after-tax, regulatory asset (\$3.7 billion, pre-tax) referred to in this annual report as the Settlement Regulatory Asset) and a related pre-tax gain of approximately \$4.9 billion on recognition of these regulatory assets. The Settlement Agreement authorizes the Utility to earn an 11.22% rate of return on equity on its rate base, including these regulatory assets. As described below, because the Utility refinanced the remaining unamortized after-tax balance of the Settlement Regulatory Asset through the issuance of approximately \$1.9 billion of energy recovery bonds, the Utility will no longer earn this 11.22% rate of return on the Settlement Regulatory Asset as it is no longer a part of rate base.

The Settlement Agreement has a term of nine years that began on the Effective Date. Although the Utility's operations are no longer subject to the oversight of the bankruptcy court, the bankruptcy court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Settlement Agreement, (2) the plan of reorganization, and (3) the bankruptcy court's December 22, 2003 order confirming the plan of reorganization. In addition, the bankruptcy court retains jurisdiction to resolve remaining disputed claims held in escrow of approximately \$1.7 billion at December 31, 2004. See Note 2 of the Notes to the Consolidated Financial Statements for further discussion.

In March 2004, in anticipation of its emergence from Chapter 11, the Utility issued \$6.7 billion in first mortgage bonds, or First Mortgage Bonds, and, together with its consolidated subsidiaries, obtained \$2.9 billion in credit facilities, in order to finance the plan of reorganization. Upon the Effective Date, the Utility paid all valid claims, deposited funds into escrow accounts for the payment of disputed claims upon resolution, and reinstated certain obligations. The Utility expects to fund its operating and capital expenditures substantially from internally generated funds. In addition, available credit facilities are considered adequate to meet these operating requirements and seasonal fluctuation in working capital.

Federal and state court appeals of the bankruptcy court's December 22, 2003 order confirming the plan of reorganization and the CPUC's approval of the Settlement Agreement remain pending. PG&E Corporation and the Utility believe these appeals and petitions are without merit. Under applicable federal precedent, once the plan of reorganization has been "substantially consummated," any pending appeals of the confirmation order should be dismissed. If, notwithstanding this federal precedent, the bankruptcy court's confirmation order or the Settlement Agreement is subsequently overturned or modified, PG&E Corporation and the Utility's financial condition and results of operations could be materially adversely affected. See Note 2 of the Notes to the Consolidated Financial Statements for further discussion.

Transition from Frozen Rates to Cost of Service Ratemaking

Beginning January 1, 1998, electricity rates were frozen as required by the California electric industry restructuring law. In 2001, in response to the California energy crisis, the CPUC increased frozen rates by imposing fixed surcharges. As a result of the Settlement Agreement and various CPUC decisions, the Utility's electricity rates as of January 1, 2004, are no longer frozen and are determined based on its costs of service, including periodic adjustments to rates to reflect changes in sales or demand compared to forecast sales or demand. The Utility's electricity and natural gas distribution rates in 2004 reflected the sum of individual revenue requirement components including:

- Base revenue requirements to recover its basic business and operational costs for electricity and natural gas distribution operations and for electricity generation operations as set by the CPUC in the Utility's 2003 GRC;
- The allowed rates of return as set in the Utility's annual cost of capital proceedings at the CPUC;
- Revenue requirements for the recovery of the regulatory assets (including an 11.22% return on equity) provided under the Settlement Agreement;
- Revenue requirements for recovery of electricity and natural gas procurement costs as authorized by the CPUC;
- Revenue requirements authorized by the FERC in the Utility's transmission owner rate cases and to recover charges imposed on the Utility for services provided by the California Independent System Operator, or ISO; and
- The revenue requirements of the California Department of Water Resources, or DWR, to meet the DWR's obligations under its long-term electricity procurement contracts entered into during the energy crisis when the California investor-owned electric utilities were unable to procure electricity.

Changes in any individual revenue requirement will affect customers' electricity rates and the Utility's revenues. As a result, the Utility's net income is more predictable under cost-of-service ratemaking than under the previous rate freeze.

In December 2004, the CPUC approved the Utility's first annual electricity rate true-up to adjust rates to reflect over- and under-collections in the Utility's major electricity balancing accounts (including electricity procurement), and consolidate various other 2005 electricity revenue requirement changes authorized by the CPUC and the FERC. These rate changes, implemented on January 1, 2005, contemplated an increase in electricity revenues of approximately \$274 million as compared to 2004 revenues at previously adopted rates. On February 7, 2005, the Utility requested the CPUC to approve a rate decrease, to be effective on March 1, 2005 of approximately \$73 million, as compared to January 1, 2005 rates, to reflect the issuance of energy recovery bonds discussed below.

2003 GRC

On May 27, 2004, the CPUC issued a decision in the Utility's 2003 GRC that determined the amount the Utility can collect from customers, or base revenue requirements, to recover its basic business and operational costs for electricity and natural gas distribution operations and for electricity generation operations for 2003 through 2006. The CPUC authorized base revenue requirements of approximately \$4.3 billion for 2003, an increase of approximately \$326 million over the previously authorized amounts. The amount of base revenue requirements authorized for 2004, 2005 and 2006, is based on the 2003 authorized amount, as increased each year to reflect the annual changes in the Consumer Price Index, or CPI, subject to certain minimum and maximum adjustments. These adjustments are called "attrition adjustments." Base revenue requirements in 2004, including attrition

adjustments totaled approximately \$4.4 billion. See "Regulatory Matters" below for further detail of the terms of the 2003 GRC.

The impact of the approval of the GRC on the Utility's results of operations and financial condition is discussed below under "Results of Operations" and "Regulatory Matters."

Elimination of Equity Ownership in NEGT

On October 29, 2004, NEGT's plan of reorganization became effective, at which time NEGT emerged from Chapter 11 and PG&E Corporation's equity ownership in NEGT was cancelled. As a result, during the fourth quarter of 2004 PG&E Corporation recognized a one-time non-cash gain on the disposal of NEGT of approximately \$684 million, as discussed below in the "Results of Operations" section.

Factors That May Affect Future Results of Operation and Financial Condition

In addition to future CPUC and FERC decisions that will affect the rates that the Utility can charge for its services and that will determine the amount of costs the Utility can recover through rates, the following significant factors are expected to affect the Utility's future results of operations and financial condition:

- The issuance of energy recovery bonds in the aggregate amount of up to \$3.0 billion;
- The amount and cost of the long-term electricity resource commitments the Utility is required to make in connection with its long-term electricity procurement plan which may involve substantial capital expenditures in new generation resources;
- The level of operating expenses;
- The performance of distribution, generation, transmission and natural gas transportation operating assets; and
- The success of the Utility's strategy to achieve cost efficiencies and operational excellence and to invest in needed infrastructure to serve the Utility's customers, resulting in improved customer service, rate base growth and future earnings under cost-of-service ratemaking.

Issuance of Energy Recovery Bonds

In connection with the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the remaining unamortized balance of the Settlement Regulatory Asset and related federal income and state franchise taxes, in an aggregate principal amount of up to \$3.0 billion in two separate series up to one year apart, to be secured by a dedicated rate component, or DRC, to be collected from electricity customers as a nonbypassable charge. On February 10, 2005, PG&E Energy Recovery Funding LLC, or PERF, a limited liability company which is wholly owned and consolidated by the Utility (but legally separate from the Utility), issued approximately \$1.9 billion of energy recovery bonds, or ERBs. The Utility, as servicer, will collect and remit DRC charges to PERF to enable PERF to pay the principal and interest on the ERBs. The proceeds of the ERBs were paid by PERF to the Utility and will be used by the Utility to refinance the remaining unamortized after-tax balance of the Settlement Regulatory Asset through the redemption and repurchase of higher cost equity and debt.

As a result of the issuance of the first series of ERBs, the Utility's 2005 net income will be reduced by approximately \$100 million as compared to 2004 due to the elimination of the 11.22% return on common equity that the Utility earned on the Settlement Regulatory Asset and charged to customers during 2004.

In January 2005, the equity component of the Utility's capital structure reached 52%, the target specified in the Settlement Agreement. The Utility anticipates that it will use surplus cash to pay

dividends to, or repurchase common stock from, PG&E Corporation. As discussed below, under "Liquidity," the Boards of Directors of the Utility and PG&E Corporation each have declared a common stock dividend and have authorized substantial share repurchases.

The proceeds of the second series of ERBs, anticipated to be issued in November 2005 in an aggregate amount of up to \$1.1 billion will be paid by PERF to the Utility to pre-fund the Utility's recovery through rates of the tax payments that will be due as the Utility collects the DRC over the term of the first series of ERBs to pay principal. The Utility anticipates that it will use the proceeds from the second series of ERBs to repay outstanding debt, or repurchase common stock from, PG&E Corporation or make additional needed investments in the Utility's rate base. Until taxes are fully paid, the Utility will compensate customers, computed at the Utility's authorized rate of return on rate base, for the use of the proceeds. This credit, along with energy supplier refunds received after the second series of ERBs is issued, other credits and costs related to the ERBs, will be reflected in rates. It is estimated that providing this "carrying cost credit" to customers could result in a decrease of up to \$60 million in the Utility's 2006 net income. The actual impact on 2006 net income will depend on the principal amount of the second series of ERBs issued, which, in turn, depends on the timing and amount of refunds the Utility receives from energy suppliers through the related FERC proceedings. The carrying cost credit and the resulting impact on net income will decline as the taxes are paid, reaching zero in 2012 when the ERBs and related taxes are paid in full. See Note 2 of the Notes to the Consolidated Financial Statements for further discussion.

Electricity Procurement Costs and Long-Term Electricity Procurement Plan

As a regulated utility, the Utility is obligated to procure electricity to meet the needs of its customers. The amount of electricity needed to meet the demands of customers, plus applicable reserve margins, that is not satisfied from the Utility's own generation facilities, the Utility's electricity purchase contracts, or from the DWR's electricity purchase contracts allocated to the Utility's customers, is referred to as the Utility's residual net open position. Electricity procurement costs significantly impacted the Utility's results of operations and financial condition during the California energy crisis. California legislation has been enacted which allows the Utility to recover its reasonably incurred wholesale electricity procurement costs and includes a mandatory rate adjustment provision that requires the CPUC to adjust rates on a timely basis to ensure that the Utility recovers its costs. Accordingly, during 2004, electricity procurement costs did not have the same impact on the Utility's results of operations that they had during the California energy crisis. The level of electricity procurement costs and revenues continue to have an impact on cash flows.

In December 2004, the CPUC issued a final decision which approved, with certain modifications, each California investor-owned electric utility's long-term electricity procurement plan, or LTPP, in order to authorize each utility to plan for and procure the resources necessary to provide reliable service to their customers for the ten-year period, 2005-2014. The utilities are required to solicit bids from providers of all potential sources of new generation (e.g., conventional or renewable resources to be provided under utility owned turnkey developments, or under third party power purchase agreements) through a single, open, transparent and competitive request for offers, or RFO, process, although a utility can tailor a RFO to meet specific resource needs.

The decision notes that there is a great degree of uncertainty as to the amount of load the existing utilities will be responsible for serving in the future. Among other provisions, the decision:

- Permits the utilities to recover their net stranded costs of all new fossil-fuel and renewable generation resources from all customers, including departing customers, for a period of 10 years or the life of the power purchase agreement, whichever is less;
- Extends the mandatory rate adjustment mechanism for wholesale electric procurement costs under California law, which otherwise would end on January 1, 2006, to the length of a resource commitment or 10 years, whichever is longer;

- Prohibits the utilities from recovering initial capital costs in excess of their final bid price for utility-owned generation resources; and
- Recognizes that the full cost (or debt equivalence) of power purchase agreements should be considered when evaluating energy contracts.

For more information, see "Regulatory Matters" below.

Operating Expenses

Operating expenses are a key factor in determining whether the Utility earns the rate of return authorized by the CPUC. Many of the Utility's costs, including electricity procurement costs, discussed above, are subject to ratemaking mechanisms that are intended to provide the Utility the opportunity to fully recover these costs. In the Utility's GRC, the CPUC authorizes the Utility to collect a fixed revenue requirement from customers that is intended to enable the Utility to recover its operating and maintenance expenses. If the Utility's operating expenses exceed the amount of the authorized revenue requirement, the Utility's results of operations and ability to earn its authorized rate of return may be affected.

Distribution, Generation, Transmission And Natural Gas Transportation Operating Assets

The Utility's distribution, generation, transmission and natural gas transportation operating assets generally consist of long-lived assets with significant construction and maintenance costs. A significant outage at any of these facilities may have a material impact on the Utility's operations. Costs associated with replacement electricity and natural gas or use of alternative facilities during these outages could have an adverse impact on PG&E Corporation's and the Utility's results of operations and liquidity.

The Utility's annual capital expenditures are expected to average approximately \$2.0 billion annually over the next five years from 2005 through 2009 and are estimated to result in rate base growth of approximately 4.5%. As discussed below under "Capital Expenditures," the Utility could make additional capital expenditures that would further increase rate base growth to 6.5% from 2005 through 2009.

Strategy to Achieve Cost Efficiencies and Operational Excellence and to Invest in Needed Utility Infrastructure

With its exit from Chapter 11 and the return to cost-of-service ratemaking for electric distribution and generation operations, the Utility aims to earn no less than its authorized rate of return, generate strong cash flow, ensure adequate liquidity, and strengthen its credit rating. To achieve these goals, the Utility's strategy is to:

- Achieve operational excellence and improved customer service;
- Generate cost and operating efficiencies; and
- Invest in transmission and distribution infrastructure needed to serve its customers (i.e., to extend the life of existing infrastructure, to replace existing infrastructure, and to add new infrastructure to meet load growth) as well as to invest in needed new generation resources, as authorized by the CPUC.

It is expected that the Utility would use cash in excess of amounts needed for operations, debt service and base capital expenditures, to pay regular quarterly dividends, to make incremental capital expenditures needed to serve its customers, and to repurchase its common stock. In turn, it is expected that PG&E Corporation would use the cash received from the Utility in the form of dividends or share repurchases to pay regular dividends to, or repurchase common stock from, its shareholders.

FORWARD-LOOKING STATEMENTS

This combined Annual Report and the letter to shareholders that accompanies it contain forward-looking statements that are necessarily subject to various risks and uncertainties the realization or resolution of which are outside of management's control. These statements are based on current expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts at the time the statements were made. These forward-looking statements are identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "might," "will," "should," "would," "could," "goal," "potential" and similar expressions. Although PG&E Corporation and the Utility are not able to predict all the factors that may affect future results, some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include:

Appeals of the Utility's Plan of Reorganization and Settlement Agreement

- The timing and resolution of the petitions for review that were filed in the California Court of Appeal for the first Appellate District, or the California Court of Appeal, seeking review of the CPUC's approval of the Settlement Agreement; and
- The timing and resolution of the pending appeals of the confirmation order.

Operating Environment

- Unanticipated changes in operating expenses or capital expenditures, which may affect the Utility's ability to earn its authorized rate of return;
- The level and volatility of wholesale electricity and natural gas prices and supplies, the Utility's ability to manage and respond to the levels and volatility successfully and the extent to which the Utility is able to timely recover increased costs related to such volatility;
- Weather, storms, earthquakes, fires, floods, other natural disasters, explosions, accidents, mechanical breakdowns and other events or hazards that affect demand, result in power outages, reduce generating output, or cause damage to the Utility's assets or operations or those of third parties on which the Utility relies;
- Unanticipated population growth or decline, changes in market demand and demographic patterns, and general economic and financial market conditions, including unanticipated changes in interest or inflation rates, and the extent to which the Utility is able to timely recover its costs in the face of such events;
- The operation of the Utility's Diablo Canyon nuclear power plant, or Diablo Canyon, which exposes the Utility to potentially significant environmental costs and capital expenditure outlays and, to the extent the Utility is unable to increase its spent fuel storage capacity by 2007 or find an alternative depository, the risk that the Utility may be required to close Diablo Canyon and purchase electricity from more expensive sources;
- Actions of credit rating agencies;
- Significant changes in the Utility's relationship with its employees, the availability of qualified personnel and the potential adverse effects if labor disputes were to occur; and
- Acts of terrorism.

Legislative and Regulatory Environment and Pending Litigation

- The impact of current and future ratemaking actions of the CPUC, including the risk of material differences between forecasted costs used to determine rates and actual costs incurred;

- Whether the assumptions and forecasts underlying the Utility's CPUC-approved long-term electricity procurement plan prove to be accurate, the terms and conditions of the generation or procurement commitments the Utility enters into in connection with its plan, the extent to which the Utility is able to recover the costs it incurs in connection with these commitments and the extent to which a failure to perform by any of the counterparties to the Utility's electricity purchase contracts or the DWR contracts allocated to the Utility's customers affects the Utility's ability to meet its obligations or to recover its costs;
- Prevailing governmental policies and legislative or regulatory actions generally, including those of the California legislature, the U.S. Congress, the CPUC, the FERC, and the Nuclear Regulatory Commission, or the NRC, with regard to the Utility's allowed rates of return, industry and rate structure, recovery of investments and costs, acquisitions and disposal of assets and facilities, treatment of affiliate contracts and relationships, and operation and construction of facilities;
- The extent to which the CPUC or the FERC delays or denies recovery of the Utility's costs, including electricity purchase costs, from customers due to a regulatory determination that such costs were not reasonable or prudent or for other reasons resulting in write-offs of regulatory balancing accounts;
- How the CPUC administers the capital structure, stand-alone dividend and first priority conditions of the CPUC's decisions permitting the establishment of holding companies for the California investor-owned electric utilities;
- The terms under which the CPUC authorizes the Utility to issue debt and equity in the future, and in particular the extent to which the conditions adopted by the CPUC, such as those contained in the CPUC's general financing authorization decision issued on October 28, 2004 (under which the Utility is authorized to issue debt and preferred stock in the future within certain amounts and for specific purposes) limit the Utility's ability to issue debt in the future;
- Whether the Utility is determined to be in compliance with all applicable rules, tariffs and orders relating to electricity and natural gas utility operations, and the extent to which a finding of non-compliance could result in customer refunds, penalties or other non-recoverable expenses;
- Whether the Utility is required to incur material costs or capital expenditures or curtail or cease operations at affected facilities to comply with existing and future environmental laws, regulations and policies; and
- The outcome of pending litigation.

Competition and Bypass

- Increased competition as a result of the takeover by condemnation of the Utility's distribution assets, duplication of the Utility's distribution assets or service by local public utilities, and other forms of competition that may result in stranded investment capital, decreased customer growth, loss of customer load and additional barriers to cost recovery; and
- The extent to which the Utility's distribution customers switch between purchasing electricity from the Utility and from alternate energy service providers as direct access customers, the extent to which cities, counties and others in the Utility's service territory begin directly serving the Utility's customers, and the extent to which the Utility's customers become self-generators, results in stranded generating asset costs and non-recoverable procurement costs.

See the section below entitled "Risk Factors" for a further discussion of the more significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future results of operations and financial condition.

RESULTS OF OPERATIONS

The table below details certain items from the accompanying Consolidated Statements of Operations for 2004, 2003 and 2002.

	Year ended December 31,		
	2004	2003	2002
	(in millions)		
Utility			
Electric operating revenues	\$ 7,867	\$ 7,582	\$ 8,178
Natural gas operating revenues	3,213	2,856	2,336
Total operating revenues	11,080	10,438	10,514
Cost of electricity	2,770	2,319	1,482
Cost of natural gas	1,724	1,467	954
Operating and maintenance	2,842	2,935	2,817
Recognition of regulatory assets	(4,900)	—	—
Depreciation, amortization and decommissioning	1,494	1,218	1,193
Reorganization professional fees and expenses	6	160	155
Total operating expenses	3,936	8,099	6,601
Operating income	7,144	2,339	3,913
Interest income	50	53	74
Interest expense	(667)	(953)	(988)
Other expense, net ⁽¹⁾	(5)	(9)	(27)
Income before income taxes	6,522	1,430	2,972
Income tax provision	2,561	528	1,178
Income before cumulative effect of a change in accounting principle	3,961	902	1,794
Cumulative effect of a change in accounting principle	—	(1)	—
Income available for common stock	\$ 3,961	\$ 901	\$ 1,794
PG&E Corporation, Eliminations and Other ⁽²⁾⁽³⁾			
Operating revenues	\$ —	\$ (3)	\$ (9)
Operating expenses	26	(7)	(50)
Operating income (loss)	(26)	4	41
Interest income	13	9	6
Interest expense	(130)	(194)	(236)
Other income (expense), net ⁽¹⁾	(93)	—	77
Income (loss) before income taxes	(236)	(181)	(112)
Income tax benefit	(95)	(70)	(41)
Income (loss) from continuing operations	(141)	(111)	(71)
Discontinued operations	684	(365)	(2,536)
Cumulative effect of changes in accounting principles	—	(5)	(61)
Net income (loss)	\$ \$543	\$ (481)	\$ (2,668)
Consolidated Total ⁽³⁾			
Operating revenues	\$ 11,080	\$ 10,435	\$ 10,505
Operating expenses	3,962	8,092	6,551
Operating income	7,118	2,343	3,954
Interest income	63	62	80
Interest expense	(797)	(1,147)	(1,224)
Other income (expenses), net ⁽¹⁾	(98)	(9)	50

Income before income taxes	6,286	1,249	2,860
Income tax provision	2,466	458	1,137
Income from continuing operations	3,820	791	1,723
Discontinued operations	684	(365)	(2,536)
Cumulative effect of changes in accounting principles	—	(6)	(61)
Net income (loss)	\$ 4,504	\$ 420	\$ (874)

(1) Includes preferred dividend requirement as other expense.

(2) PG&E Corporation eliminates all intercompany transactions in consolidation.

(3) Operating results of NEGT are reflected as discontinued operations. See Note 5 of the Notes to the Consolidated Financial Statements for further discussion.

Utility

As discussed above under "Overview," as of January 1, 2004, the Utility no longer collects frozen electricity rates. Instead, the Utility's electric rates are designed to fully recover the Utility's costs of service, including wholesale electricity procurement costs.

California legislation has been enacted which allows the Utility to recover its reasonably incurred wholesale electricity procurement costs and includes a mandatory rate adjustment provision which requires the CPUC to adjust rates on a timely basis to ensure that the Utility recovers its costs. Accordingly, with the implementation of new CPUC-approved electricity balancing accounts and cost of service ratemaking in 2004, electricity procurement costs and items such as changes in sales volumes have not had the same impact on the Utility's results of operations that they had during the California energy crisis when rates were frozen. The level of the Utility's electricity procurement costs continue to have an impact on cash flows.

Due to the recognition of the Settlement Regulatory Asset and generation-related regulatory assets provided under the Settlement Agreement, net income for 2004 reflects a one-time non-cash gain of approximately \$2.9 billion, after tax. In addition, as a result of receiving a CPUC decision in the Utility's 2003 GRC, the Utility recorded various regulatory assets and liabilities associated with revenue requirement increases, recovery of retained generation assets and unfunded taxes, depreciation and decommissioning.

The following presents the Utility's operating results for 2004, 2003, and 2002.

Electric Operating Revenues

Beginning January 1, 1998, electricity rates were frozen as required by the California electric industry restructuring law. In 2001, in response to the California energy crisis, the CPUC increased frozen rates by imposing fixed surcharges which the Utility collected through December 31, 2003. As a result of the Settlement Agreement and various CPUC decisions, the Utility's electricity rates as of January 1, 2004, are no longer frozen and are determined based on its costs of service.

As a result of the return to cost-of-service ratemaking in 2004, the Utility records its electric distribution revenues under revenue requirements approved by the 2003 GRC. Differences between the authorized revenue requirements and amounts collected by the Utility from customers in rates are tracked in regulatory balancing accounts and are reflected in miscellaneous revenues in the table below.

From mid-January 2001 through December 2002, the DWR was responsible for procuring electricity required to cover the Utility's net open position. The Utility resumed purchasing electricity on the open market in January 2003 to satisfy its residual net open position, but still relies on electricity provided under DWR contracts for a material portion of its customers' demand. Revenues collected on behalf of the DWR and the DWR's related costs are not included in the Utility's Consolidated Statements of Operations, reflecting the Utility's role as a billing and collection agent for the DWR's sales to the Utility's customers. Previously, under the frozen rate structure, increases in the revenues passed through to the DWR decreased the Utility's revenues. Starting in 2004, the Utility's electric operating revenues are based on an aggregation of individual rate components, including base revenue requirements, and electricity procurement costs, among others. Changes in the DWR's revenue requirements will not affect the Utility's revenues. Although the Utility is permitted to pass through the DWR charges to customers, any changes in the amount of DWR charges that the Utility's customers are required to pay can affect regulatory willingness to increase overall rates to permit the Utility to recover its own costs. As overall rates rise or decline, there may be changes regarding the risk of regulatory disallowance of costs.

The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio, including electricity provided under the DWR allocated contracts, in the most cost-effective way. This requirement, in certain cases, requires the Utility to schedule more electricity than is necessary to meet

its retail load and to sell this additional electricity on the open market. The Utility typically schedules excess electricity when the expected sales proceeds exceed the variable costs to operate a generation facility or buy electricity under an optional contract. Proceeds from the sale of surplus electricity are allocated between the Utility and the DWR based on the percentage of volume supplied by each entity to the Utility's total load. The Utility's net proceeds from the sale of surplus electricity after deducting the portion allocated to the DWR are recorded as a reduction to the cost of electricity.

The following table shows a breakdown of the Utility's electric operating revenues.

	2004	2003	2002
	(in millions)		
Electric revenues	\$ 9,600	\$ 10,043	\$ 10,203
DWR pass-through revenue	(1,933)	(2,243)	(2,056)
Subtotal	7,667	7,800	8,147
Miscellaneous	200	(218)	31
Total electric operating revenues	\$ 7,867	\$ 7,582	\$ 8,178
Total electricity sales (in Kwh) ⁽¹⁾	83,096	80,152	75,968

⁽¹⁾ Includes DWR electricity sales.

The Utility's electric operating revenues increased in 2004 by approximately \$285 million, or approximately 4%, compared to 2003 due to the following factors:

- The CPUC authorization for the Utility to collect the revenue requirements associated with the Settlement Regulatory Asset and the other regulatory assets provided under the Settlement Agreement resulted in an electric operating revenue increase of approximately \$490 million during 2004, compared to 2003;
- The approval of the Utility's 2003 GRC in May 2004 resulted in an electric operating revenue increase of approximately \$100 million. The GRC determines the amount the Utility can collect from its customers, or base revenue requirements (see the "Regulatory Matters" section of this MD&A);
- Electric transmission revenues increased by approximately \$400 million in 2004 compared to 2003 primarily due to an increase in recoverable reliability must run, or RMR, costs and an increase in at-risk transmission access revenues; and
- The remaining increases in the Utility's electric operating revenues were due to increases of approximately \$170 million in the Utility's authorized revenue requirements for procurement and miscellaneous other electric revenues in 2004 compared to 2003.

Partially offsetting the increase in electric operating revenues was the absence of surcharge revenues in 2004 as a result of the return to cost of service ratemaking in 2004. The Utility collected \$875 million in surcharge revenues in 2003.

In 2003, the Utility's electric operating revenues decreased approximately \$596 million, or 7%, compared to 2002.

- Surcharge revenues decreased by approximately \$900 million compared to 2002, reflecting the impact of a variety of factors including an increase in pass-through revenue to the DWR and the Utility's obligation under the Settlement Agreement to refund surcharge revenues in excess of \$875 million.

Partially offsetting this decrease was an increase of approximately \$270 million for electric distribution operations as a result of the 2003 GRC.

Cost of Electricity

The Utility's cost of electricity includes electricity purchase costs and the cost of fuel used by its owned generation facilities, but it excludes costs to operate its owned generation facilities, which are included in operating and maintenance expense. Electricity purchase costs and the cost of fuel used by owned generation facilities are passed through in rates to customers. The following table shows a breakdown of the Utility's cost of electricity and the total amount and average cost of purchased power, excluding in each case both the cost and volume of electricity provided by the DWR to the Utility's customers:

	2004	2003	2002
	(in millions)		
Cost of purchased power	\$ 2,816	\$ 2,449	\$ 1,980
Proceeds from surplus sales allocated to the Utility	(192)	(247)	—
Fuel used in own generation	146	117	97
Adjustments to purchased power accruals	—	—	(595)
Total net cost of electricity	\$ 2,770	\$ 2,319	\$ 1,482
Average cost of purchased power per kWh	\$ 0.082	\$ 0.076	\$ 0.081
Total purchased power (GWh)	34,525	32,249	24,552

In 2004, the Utility's cost of electricity increased approximately \$451 million, or 19%, as compared to 2003 mainly due to the following factors:

- The increase in total purchased power of 2,276 Gigawatt hours, or GWh, and the increase in the average cost of purchased power of \$0.006 per kWh in 2004 as compared to 2003 resulted in an increase of approximately \$367 million in the cost of purchased power; and
- The cost of electricity increased by approximately \$84 million in 2004 as compared to 2003 as a result of a decrease in the proceeds from surplus sales allocated to the Utility in 2004 and an increase in the amount of fuel used in the Utility's owned generation.

In 2003, the Utility's cost of electricity increased approximately \$837 million, or 56%, compared to 2002 mainly due to the following factors:

- The Utility's total volume of electricity purchased in 2003 increased 31% due to the fact that the Utility resumed buying and selling electricity on the open market beginning in the first quarter of 2003 to meet its residual net open position in accordance with its CPUC-approved electricity procurement plan. The increase in total purchased power of 7,697 GWh, which was partially offset by a decrease in the average cost of purchased power of \$0.005 per kWh resulted in an increase of approximately \$469 million in the cost of purchased power in 2003 compared to 2002;
- In March 2002, the Utility recorded a net reduction of approximately \$595 million to the cost of electricity as a result of FERC and CPUC decisions that allowed the Utility to reverse previously accrued ISO charges and to adjust for the amount previously accrued as payable to the DWR for the DWR's 2001 revenue requirement. There was no comparable reduction in 2003; and
- As the Utility resumed procuring power on behalf of its customers, it was sometimes required to dispatch more electricity than was necessary to meet its retail load, and to sell this additional electricity on the open market. Proceeds from surplus electricity sales, offset by an increase in the amount of fuel used in the Utility's owned generation reduced the total cost of electricity by approximately \$227 million in 2003 compared to 2002.

The Utility's cost of electricity in 2005 will depend upon electricity prices and the amount of the Utility's residual net open position (see the "Risk Factors" section of this MD&A).

Natural Gas Operating Revenues

The Utility sells natural gas and provides natural gas transportation services to its customers. The Utility's natural gas customers consist of two categories: core and noncore customers. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The noncore customer class is comprised of industrial and larger commercial natural gas customers. The Utility provides natural gas delivery services to all core and noncore customers connected to the Utility's system in its service territory. Core customers can purchase natural gas from alternate energy service providers or can elect to have the Utility provide both delivery service and natural gas supply. When the Utility provides both supply and delivery, the Utility refers to the service as natural gas bundled service. In 2004, core customers represented over 99% of the Utility's total customers and approximately 35% of its total natural gas deliveries, while noncore customers comprised less than 1% of the Utility's total customers and approximately 65% of its total natural gas deliveries.

The Utility's transportation system transports gas throughout California to the Utility's distribution system, which, in turn, delivers gas to end-use customers. Utility transportation and distribution services for all customers have historically been bundled or sold together at a combined rate.

The following table shows a breakdown of the Utility's natural gas operating revenues:

	2004	2003	2002
	(in millions)		
Bundled natural gas revenues	\$ 2,943	\$ 2,572	\$ 2,020
Transportation service-only revenues	270	284	316
Total natural gas operating revenues	\$ 3,213	\$ 2,856	\$ 2,336
Average bundled revenue per Mcf of natural gas sold	\$ 10.51	\$ 9.22	\$ 7.16
Total bundled natural gas sales (in millions of Mcf)	280	279	282

The Utility's natural gas operating revenues increased approximately \$357 million, or 13%, for the year ended December 31, 2004, compared to 2003. The increase in natural gas operating revenues was primarily due to the following factors:

- Bundled natural gas revenues (excluding the effects of the 2003 GRC decision discussed below) increased by approximately \$250 million, or 10%, in 2004 compared to 2003, mainly due to a higher cost of natural gas which the Utility is permitted by the CPUC to pass on to its customers through higher rates. The average bundled revenue per thousand cubic feet, or Mcf, of natural gas sold in 2004 (excluding the effects of the 2003 GRC decision discussed below) increased by approximately \$0.86, or 9%, as compared to 2003; and
- The approval of the 2003 GRC resulted in an increase in natural gas revenues of approximately \$121 million (consisting of a 2004 portion of \$69 million and a 2003 portion of \$52 million) in 2004 compared to 2003 (see the "Regulatory Matters" section of this MD&A).

In 2003, the Utility's total natural gas operating revenues increased approximately \$520 million, or 22%, compared to 2002. The Utility's bundled natural gas revenues increased by approximately \$552 million, or 27%, in 2003 compared to 2002 mainly due to a higher average cost of natural gas, which the Utility is permitted by the CPUC to pass on to its customers through higher rates. The average bundled revenue per Mcf of natural gas sold in 2003 increased \$2.06, or 29%, compared to 2002. This increase in bundled natural gas revenues was partially offset by a decrease in transportation service-only revenues of approximately \$32 million, or 10%, in 2003 compared to 2002. The decrease in transportation service-only revenues was primarily due to a decrease in demand for natural gas transportation services by certain non-core customers, mainly natural gas-fired electric generators in California. An increase in electricity available from hydroelectric facilities and the greater efficiency of

generation facilities that commenced operations in 2003 resulted in reduced demand for natural gas transportation services.

The Utility's natural gas revenues in 2005 will increase due to an increase in natural gas distribution revenue requirements that were approved in the 2003 GRC decision, and will be further impacted by changes in the cost of natural gas.

Cost of Natural Gas

The Utility's cost of natural gas includes the purchase cost of natural gas and transportation costs on interstate pipelines, but excludes the costs associated with the Utility's intrastate pipeline, which are included in operating and maintenance expense. The following table shows a breakdown of the Utility's cost of natural gas:

	2004	2003	2002
	(in millions)		
Cost of natural gas sold	\$ 1,591	\$ 1,336	\$ 853
Cost of natural gas transportation	133	131	101
Total cost of natural gas	\$ 1,724	\$ 1,467	\$ 954
Average cost per Mcf of natural gas sold	\$ 5.68	\$ 4.79	\$ 3.02
Total natural gas sold (in millions of Mcf)	280	279	282

In 2004 the Utility's total cost of natural gas increased approximately \$257 million, or 18%, as compared to 2003, primarily due to an increase in the average market price of natural gas purchased of approximately \$0.89 per Mcf.

In 2003, the Utility's total cost of natural gas increased by approximately \$513 million, or 54%, compared to 2002 mainly due to the following factors:

- The Utility's cost of natural gas sold increased by approximately \$483 million, or 57%, in 2003 compared to 2002 mainly due to an increase in the average cost of natural gas in 2003 of \$1.77 per Mcf, or 59%; and
- The Utility's cost of natural gas transportation increased by approximately \$30 million, or 30%, in 2003 compared to 2002 mainly due to pipeline transportation charges paid to El Paso Natural Gas Company, or El Paso. The Utility, along with other California utilities, was ordered by the CPUC in July 2002 to enter into new long-term contracts to purchase firm transportation services on the El Paso pipeline, under which the Utility pays a fixed amount to secure capacity on the El Paso pipeline.

The Utility's cost of natural gas sold in 2005 will be primarily affected by the prevailing costs of natural gas, which are determined by North American regions that supply the Utility.

Operating and Maintenance

Operating and maintenance expenses consist mainly of the Utility's costs to operate and maintain its electricity and natural gas facilities, customer accounts and service expenses, public purpose program expenses, and administrative and general expenses.

During 2004, the Utility's operating and maintenance expenses decreased by approximately \$93 million, or 3%, compared to 2003. This decrease is primarily due to the establishment of a regulatory asset of approximately \$50 million in 2004 related to distribution-related electric industry restructuring costs incurred during the period from 1999 through 2002 that were previously not considered probable of recovery. During 2004, the CPUC adopted a proposed settlement agreement that permits recovery of a portion of these costs (see the "Regulatory Matters" section of this MD&A).

In 2003, the Utility's operating and maintenance expenses increased by approximately \$118 million, or 4%, compared to 2002 mainly due to a reversal of a liability of approximately \$65 million for surcharge revenues in excess of ongoing procurement costs and surcharge revenue collections at the end of 2002. The remainder of the increase was mainly due to wage increases in 2003 and increases in employee benefit plan-related expenses due to a 15% decrease in returns on plan investments and a decrease in the discount rates used to calculate the present value of the Utility's benefit obligations from 6.75% to 6.25%.

Recognition of Regulatory Assets

In light of the satisfaction of various conditions to the implementation of the Utility's plan of reorganization, the Utility recorded the regulatory assets provided for under the Settlement Agreement in the first quarter of 2004. This resulted in the recognition of a one-time non-cash, pre-tax gain of \$3.7 billion for the Settlement Regulatory Asset and \$1.2 billion for the Utility retained generation regulatory assets, for a total after-tax gain of \$2.9 billion. See the "Overview" section of this MD&A and Note 2 of the Notes to the Consolidated Financial Statements for further discussion.

Depreciation, Amortization and Decommissioning

The Utility charges the original cost of retired plant and removal costs less salvage value to accumulated depreciation upon retirement of plant in service for its lines of business that apply SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended, or SFAS No. 71, which includes electricity and natural gas distribution, electricity generation and transmission, and natural gas transportation and storage.

In 2004, the Utility's depreciation, amortization and decommissioning expenses increased by approximately \$276 million, or 23%, compared to 2003, primarily as a result of the amortization of the Settlement Regulatory Asset and an increase in the Utility's plant assets.

In 2003, the Utility's depreciation, amortization and decommissioning expenses increased by approximately \$25 million, or 2%, compared to 2002 mainly due to an increase in the Utility's plant assets.

Reorganization Fees and Expenses

In accordance with the American Institute of Certified Public Accountants' Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," or SOP 90-7, the Utility reports reorganization fees and expenses separately on its Consolidated Statements of Operations. These costs mainly include professional fees for services in connection with the Utility's Chapter 11 proceedings and totaled approximately \$6 million in 2004, \$160 million in 2003 and \$155 million in 2002. The Utility discontinued reporting in accordance with SOP 90-7 upon its emergence from Chapter 11 on April 12, 2004.

Interest Income

In accordance with SOP 90-7, the Utility reports reorganization interest income separately on its Consolidated Statements of Operations. Reorganization interest income mainly includes interest earned on cash accumulated during the Utility's Chapter 11 proceedings. Interest income, including reorganization interest income, decreased by approximately \$3 million, or 6%, in 2004 from 2003 and approximately \$21 million, or 28%, in 2003 from 2002. Both decreases were mainly due to lower average interest rates earned on the Utility's short-term investments.

Interest Expense

In 2004, the Utility's interest expense decreased by approximately \$286 million, or 30%, compared to 2003 mainly due to a lower average amount of unpaid debt accruing interest and a lower weighted average interest rate on debt outstanding during 2004 compared to 2003. As a result of this interest savings, the CPUC reduced the Utility's authorized cost of capital revenue requirement in 2004 (see the "Regulatory Matters" section of this MD&A).

In 2003, the Utility's interest expense decreased by approximately \$35 million, or 4%, compared to 2002 mainly due to the reduction in the amount of rate reduction bonds outstanding, reflecting the declining principal balance of the rate reduction bonds and a lower amount of unpaid debts accruing interest. See Note 3 of the Notes to the Consolidated Financial Statements for further discussion. This decrease was partially offset by the accrual of \$38 million in interest payable to the DWR in 2003.

Income Tax Expense

In 2004, the Utility's income tax expense increased by approximately \$2.0 billion, or 387%, as compared to 2003, mainly due to an increase in pre-tax income of approximately \$5.1 billion for the year ended December 31, 2004, primarily as a result of the recognition of regulatory assets associated with the Settlement Agreement, as compared to the same period in 2003. This increase was partially offset by the recognition of tax regulatory assets established upon receipt of the Utility's 2003 GRC decision. The effective tax rate for the year ended December 31, 2004 increased by 2.9 percentage points. This increase is due mainly to increases in the effect of regulatory treatment of depreciation differences and lower tax credit amortization in 2004.

In 2003, the Utility's income tax expense decreased by approximately \$650 million, or 55%, as compared to 2002, mainly due to a decrease in pre-tax income of approximately \$1.5 billion for the year ended December 31, 2003. In 2003 the effective tax rate decreased by 2.9 percentage points from 2002. The decrease is due mainly to the effect of regulatory treatment of depreciation differences.

PG&E Corporation, Eliminations and Others

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up. Operating expenses allocated to affiliates are eliminated in consolidation.

The increase in operating expenses was primarily due to the absence of entries in 2004 to eliminate the cost of natural gas and electricity expenses provided by NEGT to the Utility after PG&E Corporation's deconsolidation of NEGT effective July 7, 2003. A reduction in general and administrative expenses in 2004 compared to 2003 partly offset this increase.

In 2003, the increase in operating expenses of approximately \$43 million compared to the same period in 2002, was primarily attributable to increased employee compensation plan expenses, partly offset by a decrease in consulting services and outside attorney fees related to the Utility's plan of reorganization.

Interest Expense

PG&E Corporation's interest expense is not allocated to its affiliates. In 2004, PG&E Corporation's interest expense decreased by approximately \$64 million, or 33%, compared to 2003 due to a reduction in principal debt amount outstanding and lower interest rates in 2004 compared to 2003, as well as a write-off of approximately \$89 million of unamortized loan fees, loan discount, and

prepayment fees associated with the repayment in July 2003 of approximately \$735 million of principal and interest under PG&E Corporation's then existing credit agreement. This decrease in interest expense was partly offset by a redemption premium of approximately \$51 million and a charge due to the write-off of approximately \$15 million of unamortized loan fees associated with the redemption of PG&E Corporation's \$600 million of 6⁷/₈ % Senior Secured Notes due 2008, or Senior Secured Notes, on November 15, 2004.

In 2003, PG&E Corporation's interest expense decreased by approximately \$42 million, or 18%, compared to 2002. The decrease was mainly due to a decrease in amortization of deferred charges and unamortized loan fees during 2003, compared to 2002. During the third quarter of 2003, PG&E Corporation wrote off approximately \$89 million as described above, while during the third quarter of 2002, PG&E Corporation wrote off \$153 million of unamortized loan fees and discounts when it repaid principal and modified a loan under PG&E Corporation's credit agreement.

Other Income (Expense)

PG&E Corporation's other expense increased by approximately \$93 million in 2004 compared to 2003. The increase was primarily due to a pre-tax charge to earnings, related to the change in market value of non-cumulative dividend participation rights included within PG&E Corporation's \$280 million of 9.50% Convertible Subordinated Notes due 2010, or Convertible Subordinated Notes.

In 2003, PG&E Corporation's other income decreased by approximately \$77 million, compared to 2002, due to the third quarter of 2002 change in the market value of NEGТ warrants. In 2001, PG&E Corporation granted to affiliates of lenders through which it was refinancing debt, warrants to purchase up to 2% or 3% of NEGТ's outstanding common stock (depending on how long the loans were outstanding). These warrants were originally recorded at their fair value of approximately \$151 million. The fair value of the warrants was marked to market at the end of each reporting period. Changes in fair value of the warrants were recorded as other non-operating expense or income. In the third quarter of 2002, approximately \$71 million was recorded in other non-operating income to reflect the reduction to zero of the fair value of the 3% warrants. The 3% warrants were exercised during the first quarter of 2003.

Discontinued Operations

Effective July 8, 2003 (the date NEGТ filed a voluntary petition for relief under Chapter 11), NEGТ and its subsidiaries were no longer consolidated by PG&E Corporation in its Consolidated Financial Statements. Under accounting principles generally accepted in the United States of America, or GAAP, consolidation is generally required for entities owning more than 50% of the outstanding voting stock of an investee, except when control is not held by the majority owner. Legal reorganization and bankruptcy represent conditions that can preclude consolidation in instances where control rests with an entity other than the majority owner. In anticipation of NEGТ's Chapter 11 filing, PG&E Corporation's representatives who previously served on the NEGТ Board of Directors resigned on July 7, 2003, and were replaced with Board members who are not affiliated with PG&E Corporation. As a result, PG&E Corporation no longer retained significant influence over the ongoing operations of NEGТ.

Accordingly, PG&E Corporation has reflected the loss from operations of NEGТ through July 7, 2003 as discontinued operations in its Consolidated Statements of Operations. In addition, PG&E Corporation's negative investment in NEGТ of approximately \$1.2 billion was reflected as a single amount, under the cost method, within the December 31, 2003 Consolidated Balance Sheet of PG&E Corporation. This negative investment represents the losses of NEGТ recognized by PG&E Corporation in excess of its investment in and advances to NEGТ.

On October 29, 2004, NEGТ's plan of reorganization became effective, at which time NEGТ emerged from Chapter 11 and PG&E Corporation's equity ownership in NEGТ was cancelled. On the

effective date, PG&E Corporation reversed its negative investment in NEGT and also reversed net deferred income tax assets of approximately \$428 million and a charge of approximately \$120 million (\$77 million, after tax), in accumulated other comprehensive income, related to NEGT. The resulting net gain has been offset by the \$30 million payment made by PG&E Corporation to NEGT pursuant to the parties' settlement of certain tax-related litigation and other adjustments to NEGT-related liabilities. A summary of the effect on the quarter and year ended December 31, 2004 earnings from discontinued operations is as follows:

	(in millions)
Investment in NEGT	\$ 1,208
Accumulated other comprehensive income	(120)
Cash paid pursuant to settlement of tax related litigation	(30)
Tax effect	(374)
Gain on disposal of NEGT, net of tax	\$ 684

At December 31, 2004, PG&E Corporation's Consolidated Balance Sheet includes approximately \$138 million in income tax liabilities (including \$86 million in current income taxes payable) and approximately \$25 million of other net liabilities related to NEGT. Until PG&E Corporation reaches final settlement of these obligations, it will continue to disclose fluctuations in these estimated liabilities in discontinued operations. Beginning on the effective date of NEGT's plan of reorganization, PG&E Corporation no longer includes NEGT or its subsidiaries in its consolidated income tax returns.

PG&E Corporation recorded losses from discontinued operations of approximately \$365 million in 2003 and approximately \$2.5 billion in 2002.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The level of PG&E Corporation and the Utility's current assets and current liabilities is subject to fluctuation as a result of seasonal demand for electricity and natural gas, energy commodity costs, and the timing and effect of regulatory decisions and financings, among other factors. The Utility will use the proceeds of the issuance of the ERBs it received from PERF, the issuer of the ERBs, to refinance the remaining unamortized balance of the Settlement Regulatory Asset through the redemption and repurchase of higher cost equity and debt. The Utility plans to use a portion of the ERB proceeds to defease \$600 million of Floating Rate First Mortgage Bonds by the end of February 2005, retire \$300 million of short-term debt, and repurchase approximately \$960 million of its common stock from PG&E Corporation.

In January 2005, the equity component of the Utility's capital structure reached 52%, the target specified in the Settlement Agreement. As discussed below, on February 16, 2005, the Boards of Directors of the Utility and PG&E Corporation each declared a common stock dividend. In addition, PG&E Corporation anticipates that it will repurchase shares of its common stock of up to \$1.05 billion, increased from a previous authorization of up to \$975 million.

Liquidity

PG&E Corporation and the Utility intend to retain sufficient cash for operating needs and to manage debt levels to maintain access to credit. Available cash, combined with cash from operations and cash generated from refinancing of the Settlement Regulatory Asset will be used for planned capital expenditures and repayment of existing long-term debt. Surplus cash either will be returned to investors through dividend payments and/or share repurchases or utilized to fund incremental capital investments.

PG&E Corporation and the Utility seek to manage their liquidity and capital resources within the following parameters and assumptions:

- PG&E Corporation and the Utility target cash balances, which, together with credit facilities, accommodates normal and unforeseen demands on its liquidity. Currently, PG&E Corporation and the Utility have credit facilities totaling \$200 million and \$1.5 billion, respectively;
- The Utility seeks to maintain or strengthen its credit ratings to provide efficient access to financial and trade credit and to ensure adequate liquidity. The Utility's issuer credit ratings, as of February 16, 2005, are BBB from Standard & Poor's, or S&P, and Baa3 from Moody's Investors Service, or Moody's. The Utility's secured debt ratings are currently BBB from S&P and Baa2 from Moody's;
- The Utility seeks to manage its operating expenses and capital expenditures to earn not less than its 11.22% authorized rate of return on the equity portion of its authorized rate base assets. Under the Settlement Agreement, the Utility's authorized return on equity floor of 11.22% and allowed equity ratio of 52% cannot be reduced until its long-term issuer credit ratings are at least A- from S&P or A3 from Moody's;
- The Utility estimates average capital expenditures of approximately \$2.0 billion annually over the next five years (excluding additional potential capital expenditures as discussed below under "Capital Expenditures");
- The Utility assumes that the second series of ERBs in the approximate amount of up to \$1.1 billion will be issued in November 2005;
- The Utility assumes that its total natural gas and electric rate base will grow at the rate of 4.5%-6.5% per year over the next five years, depending on the level of capital spending for infrastructure needs. Rate base is expected to reach approximately \$15.3 billion in 2005 and \$16.0 billion in 2006; and
- The Utility remains under cost-of-service regulation by the CPUC and, with respect to electricity transmission, the FERC, and the CPUC authorizes sufficient revenues for the Utility to recover its energy procurement and base expenses.

At December 31, 2004, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately \$1.0 billion, and restricted cash of approximately \$2.0 billion. PG&E Corporation and the Utility maintain separate bank accounts. At December 31, 2004, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately \$189 million. At December 31, 2004, the Utility had cash and cash equivalents of approximately \$783 million, and restricted cash of approximately \$2.0 billion. The Utility's restricted cash includes amounts deposited in escrow related to the remaining disputed Chapter 11 claims, collateral required by the ISO and deposits under certain third party agreements. PG&E Corporation and the Utility primarily invest their cash in money market funds and in short-term obligations of the U.S. Government and its agencies.

Dividends

PG&E Corporation and the Utility did not declare or pay a dividend during the Utility's Chapter 11 proceeding as the Utility was prohibited from paying any common or preferred stock dividends without bankruptcy court approval and certain covenants in PG&E Corporation's Senior Secured Notes restricted the circumstances in which such a dividend could be declared or paid. With the Utility's emergence from Chapter 11 on April 12, 2004, the Utility resumed the payment of preferred stock dividends.

On February 16, 2005, the Board of Directors of the Utility declared a cash dividend of \$117 million on the Utility's common stock for the first quarter of 2005. The dividend was paid to PG&E Corporation and PG&E Holdings LLC, a wholly owned subsidiary of the Utility that holds

approximately 6% of the Utility's common stock, on February 17, 2005. Also, on February 16, 2005, the Board of Directors of PG&E Corporation declared a cash dividend of \$0.30 per share on PG&E Corporation's common stock for the first quarter of 2005, payable on April 15, 2005, to shareholders of record on March 31, 2005. These actions are consistent with the dividend policy and target dividend payout ratio range (the proportion of earnings paid out as dividends) adopted by both Boards in October 2004. PG&E Corporation's and the Utility's dividend policies contemplate a target dividend payout ratio range of 50-70% and PG&E Corporation's policy targets an initial annual cash dividend of \$1.20 per share (\$0.30 quarterly).

PG&E Corporation's and the Utility's dividend policies are designed to meet the following three objectives:

- **Comparability:** Pay a dividend competitive with the securities of comparable companies based on payout ratio and, with respect to PG&E Corporation, yield (i.e., dividend divided by share price);
- **Flexibility:** Allow sufficient cash to pay a dividend and to fund investments while avoiding the necessity to issue new equity unless PG&E Corporation's or the Utility's capital expenditure requirements are growing rapidly and PG&E Corporation or the Utility can issue equity at reasonable cost and terms; and
- **Sustainability:** Avoid reduction or suspension of the dividend despite fluctuations in financial performance except in extreme and unforeseen circumstances.

The target dividend payout ratio range was based on an analysis of dividend payout ratios of comparable companies. The initial dividend target was chosen in recognition of the Utility's current credit rating and the potential capital investments that the Utility may make in the future to provide electricity resource adequacy in compliance with future regulatory requirements and an approved LTPP.

Each Board of Directors retains authority to change its common stock dividend policy and its dividend payout ratio at any time, especially if unexpected events occur that would change the Board's views as to the prudent level of cash conservation.

Stock Repurchases

During the fourth quarter of 2004, 1,863,600 shares of PG&E Corporation common stock were repurchased through transactions with brokers and dealers on the New York Stock Exchange and/or the Pacific Exchange for an aggregate purchase price of approximately \$60 million. Of this amount, 850,000 shares are held by Elm Power Corporation, a wholly owned subsidiary of PG&E Corporation.

In addition, on December 15, 2004, PG&E Corporation entered into accelerated share repurchase arrangements with Goldman, Sachs & Co., or GS&Co., under which PG&E Corporation repurchased 9,769,600 shares of its common stock for an aggregate of purchase price of approximately \$318 million. The repurchased shares were retired. PG&E Corporation will pay GS&Co. approximately \$14 million on February 22, 2005, to settle its obligations to pay GS&Co. a price adjustment based on the daily volume weighted average market price of PG&E Corporation common stock over the term of the arrangement.

On December 15, 2004, the Board of Directors of the Utility authorized the repurchase of up to \$800 million (which has been increased to \$1.8 billion following the receipt of proceeds from the issuance of ERBs) of the Utility's common stock from PG&E Corporation, with such repurchases to be effective from time to time, but no later than December 31, 2006. Based on the expected receipt of funds, on December 15, 2004, PG&E Corporation's Board of Directors authorized the repurchase of up to \$975 million of its outstanding common stock.

On February 16, 2005, the Board of Directors of PG&E Corporation increased this authorization to \$1.05 billion with such repurchases to be effected from time to time, but no later than June 30,

2006. PG&E Corporation expects to enter into a replacement accelerated share repurchase arrangement by early March 2005 to repurchase an aggregate of \$1.05 billion of its outstanding shares. The repurchased shares will be retired at that time.

Utility

Operating Activities

The Utility's cash flows from operating activities consist of sales to its customers and payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. Cash flows from operating activities are also impacted by collections of accounts receivable and payments of liabilities previously recorded.

The Utility's cash flows from operating activities for 2004, 2003 and 2002 were as follows:

	2004	2003	2002
	(in millions)		
Net income	\$ 3,982	\$ 923	\$ 1,819
Non-cash (income) expenses:			
Depreciation, amortization and decommissioning	1,494	1,218	1,193
Gain on establishment of regulatory asset, net	(2,904)	—	—
Net reversal of ISO accrual	—	—	(970)
Change in accounts receivable	(85)	(590)	212
Change in accrued taxes	52	48	(345)
Other uses of cash:			
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(1,022)	(87)	(1,442)
Other changes in operating assets and liabilities	454	458	667
Net cash provided by operating activities	\$ 1,971	\$ 1,970	\$ 1,134

In 2004, net cash provided by operating activities approximated 2003 levels. This is mainly due to the following factors:

- Net income increased approximately \$431 million, excluding the one-time non-cash gain, after-tax, of approximately \$2.9 billion related to the recognition of the regulatory assets established under the Settlement Agreement and including \$276 million for the impact of depreciation, amortization, and decommissioning which are also non-cash items;
- Accounts receivable increased approximately \$505 million primarily due to there being no similar settlement in 2004 for the 2003 DWR settlement discussed below; and
- Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise increased approximately \$935 million due to payment of all allowed creditor claims on the Effective Date.

In 2003, net cash provided by operating activities increased by approximately \$836 million compared to 2002, even though net income decreased by \$896 million in 2003. This is mainly due to the following factors:

- Payments on amounts classified as liabilities subject to compromise decreased by approximately \$1.4 billion in 2003, compared to 2002 due to significant pre-petition and post-petition payments made in 2002 under bankruptcy court-approved settlements;
- This was partially offset by an increase in accounts receivable of approximately \$802 million. This increase was mainly due to the settlement in 2003 of an amount payable to the DWR that was recorded as an offset to the Utility's customer accounts receivable balance in 2002. Amounts

payable to the DWR are offset against amounts receivable from the Utility's customers for energy supplied by the DWR reflecting the Utility's role as a billing and collection agent for the DWR's sales to the Utility's customers;

- During 2002, the Utility overpaid income taxes resulting in an increase of \$393 million of accrued taxes; and
- Net income in 2002 included a non-cash reduction of approximately \$970 million to cost of electricity related to the reversal of ISO charges.

Investing Activities

The Utility's investing activities consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. Cash flows from operating activities have been sufficient to fund the Utility's capital expenditure requirements during 2004, 2003 and 2002. Year to year variances depend upon the amount and type of construction activities, which can be influenced by storm and other damage.

The Utility's cash flows from investing activities for 2004, 2003 and 2002 were as follows:

	2004	2003	2002
	<u> </u>	<u> </u>	<u> </u>
	(in millions)		
Capital expenditures	\$ (1,559)	\$ (1,698)	\$ (1,546)
Net proceeds from sale of assets	35	49	11
Increase in restricted cash	(1,710)	—	—
Other investing activities, net	(178)	(114)	26
	<u> </u>	<u> </u>	<u> </u>
Net cash used by investing activities	\$ (3,412)	\$ (1,763)	\$ (1,509)
	<u> </u>	<u> </u>	<u> </u>

In 2004, net cash used by investing activities increased by approximately \$1.6 billion as compared to 2003. This increase was mainly due to an increase in restricted cash of approximately \$1.7 billion in 2004 reflecting a deposit of funds into an escrow account to pay disputed Chapter 11 claims when resolved. This was partially offset by a decrease of \$139 million in capital expenditures in 2004 compared to 2003 primarily due to delays in electric transmission line capacity projects.

In 2003, net cash used by investing activities increased by approximately \$254 million compared to 2002. This increase was mainly due to an increase in capital expenditures related to electricity transmission network upgrades and new electricity capacity and transmission development projects in 2003 and other investing activities during 2003. Cash flows from other investing activities related mainly to nuclear decommissioning funding and the change in nuclear fuel inventory during the period.

Financing Activities

During its Chapter 11 proceeding, the Utility's financing activities were limited to repayment of secured debt obligations as authorized by the bankruptcy court. During this period, the Utility did not have access to the capital markets. In March 2004, in anticipation of its emergence from Chapter 11, the Utility issued significant amounts of debt in order to finance its payments to be made in connection with the implementation of the plan of reorganization on the Effective Date. The Utility also established a working capital facility and an accounts receivable financing facility for the purposes of funding its operating expenses and seasonal fluctuations in working capital and providing letters of credit.

The Utility's cash flows from financing activities for 2004, 2003 and 2002 were as follows:

	2004	2003	2002
	(in millions)		
Net proceeds from long-term debt issued	\$ 7,742	\$ —	\$ —
Net proceeds under credit facilities and short-term borrowings	300	—	—
Rate reduction bonds matured	(290)	(290)	(290)
Long-term debt, matured, redeemed or repurchased	(8,402)	(281)	(333)
Preferred dividends paid	(90)	—	—
Preferred stock redeemed	(15)	—	—
Net cash used by financing activities	\$ (755)	\$ (571)	\$ (623)

In 2004, net cash used by financing activities increased by approximately \$184 million as compared to 2003. This was mainly due to the following factors:

- In March 2004 the Utility consummated a public offering of \$6.7 billion in First Mortgage Bonds. On the Effective Date, the Utility entered into pollution control bond bridge loans in the amount of \$454 million and borrowed \$350 million under the accounts receivable financing facility. In June 2004, the Utility entered into four separate loan agreements with the California Pollution Control Financing Authority, which issued \$345 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds. See Note 3 of the Notes to the Consolidated Financial Statements for further discussion;
- Partially offsetting these proceeds are issuance costs of approximately \$107 million associated with the \$6.7 billion in First Mortgage Bonds, working capital facilities, bridge loans and other exit financing activities;
- In November 2004, the Utility borrowed \$300 million under its \$850 million credit facility; the \$300 million was repaid on February 11, 2005;
- Approximately \$290 million of rate reduction bonds matured during 2004;
- The amount of long-term debt, matured, redeemed or repurchased includes \$310 million paid in March 2004 upon maturity of secured debt, \$6.9 billion of long-term debt paid on the Effective Date, \$350 million borrowed on the Effective Date under the accounts receivable financing facility and repaid in May 2004, and \$345 million of pollution control bond-related bridge loans that were repaid in June 2004;
- In October 2004, \$500 million of Floating Rate First Mortgage Bonds were redeemed;
- Approximately \$90 million of preferred stock dividends were paid during 2004; and
- Approximately \$15 million of preferred stock with mandatory redemption provisions was redeemed during 2004.

In 2003, net cash used by financing activities decreased by approximately \$52 million compared to 2002. With bankruptcy court approval, the Utility repaid approximately \$281 million in principal on its mortgage bonds that matured in August 2003, which was a decrease of approximately \$52 million from 2002.

PG&E Funding, LLC, a wholly owned subsidiary of the Utility, also repaid approximately \$290 million in principal on its rate reduction bonds in 2003 and 2002. PG&E Funding, LLC was not included in the Utility's Chapter 11 proceeding. PG&E Funding, LLC pays the principal and interest on the rate reduction bonds from a specific rate element in Utility customers' bills. See Note 4 of the Notes to the Consolidated Financial Statements for further discussion. The Utility remits the collection of these billings to PG&E Funding, LLC on a daily basis.

PG&E Corporation

As of December 31, 2004, PG&E Corporation had stand-alone cash and cash equivalents of approximately \$189 million. PG&E Corporation's sources of funds are dividends and share repurchases from the Utility, issuance of its common stock and external financing. The Utility did not pay any dividends to, nor repurchase shares from, PG&E Corporation during 2004, 2003, or 2002.

Operating Activities

PG&E Corporation's consolidated cash flows from operating activities consist mainly of billings to the Utility for services rendered and payments for employee compensation and goods and services provided by others to PG&E Corporation. PG&E Corporation also incurs interest costs associated with its debt.

PG&E Corporation's consolidated cash flows from operating activities for 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in millions)	
Net income (loss)	\$ 4,504	\$ 420	\$ (874)
Gain on disposal of NEGT (net of income taxes of \$374 million)	(684)	—	—
Loss from discontinued operations	—	365	2,536
Cumulative effect of changes in accounting principles	—	6	61
Net income from continuing operations	3,820	791	1,723
Non-cash (income) expenses:			
Depreciation, amortization and decommissioning	1,497	1,222	1,196
Deferred income taxes and tax credits—net	611	190	(281)
Recognition of regulatory asset, net of tax	(2,904)	—	—
Other deferred charges and noncurrent liabilities	(519)	857	921
Loss from retirement of long-term debt	65	89	153
Gain of sale of assets	(19)	(29)	—
Tax benefit from employee stock plans	41	—	—
Other changes in operating assets and liabilities:	(242)	(618)	(2,898)
Net cash provided by operating activities	\$ 2,350	\$ 2,502	\$ 814

In 2004 the net cash provided by operating activities decreased by \$152 million, compared to 2003 due to 2004 payments totaling approximately \$85 million for PG&E Corporation's senior executive retention program and \$30 million pursuant to a settlement of certain tax-related litigation between PG&E Corporation and NEGT. There were no similar payments in the prior year.

In 2003, PG&E Corporation's consolidated cash flows provided by operating activities increased by approximately \$1.7 billion compared to 2002, mainly due to an increase in the Utility's net cash provided from operating activities, partially offset by a decrease in net cash provided from NEGT's operating activities as a result of realized losses generated through July 7, 2003.

Investing Activities

PG&E Corporation, on a stand-alone basis, did not have any material investing activities in the years ended December 31, 2004, 2003 and 2002.

Financing Activities

PG&E Corporation's cash flows from financing activities consist mainly of cash generated from debt refinancing and the issuance of common stock.

PG&E Corporation's cash flows from financing activities for 2004, 2003 and 2002 were as follows:

	2004	2003	2002
		(in millions)	
Net borrowings under credit facilities and short-term borrowings	\$ 300	\$ —	\$ —
Net proceeds from long-term debt issued	7,742	581	847
Long-term debt matured, redeemed or repurchased	(9,054)	(1,068)	(1,241)
Rate reduction bonds matured	(290)	(290)	(290)
Preferred stock with mandatory redemption provisions redeemed	(15)	—	—
Common stock issued	162	166	217
Common stock repurchased	(378)	—	—
Preferred dividends paid	(90)	—	—
Other, net	(1)	(4)	—
Net cash used by financing activities	\$ (1,624)	\$ (615)	\$ (467)

In 2004, PG&E Corporation's consolidated net cash used by financing activities increased by approximately \$1,009 million, compared to 2003. The increase is primarily due to the November 15, 2004 redemption of PG&E Corporation's Senior Secured Notes for which PG&E Corporation paid approximately \$664.5 million which included a redemption premium of approximately \$50.7 million and \$13.8 million of interest accrued since the last interest payment date. During November and December of 2004, PG&E Corporation repurchased 10,783,200 shares of PG&E Corporation common stock at a cost of approximately \$350 million and 850,000 shares repurchased through Elm Power Corporation, PG&E Corporation's subsidiary, at a value of \$28 million.

In 2003, net cash used by financing activities increased by \$148 million compared to 2002 mainly due to a decrease in common stock issued for 401(k) plan stock purchases and stock option and warrant exercises and a decrease in net proceeds from long-term debt issued. In 2002, PG&E Corporation refinanced a credit facility, which was further amended to increase the size of the facility in October 2002 to a total of \$720 million. In addition, in June 2002, PG&E Corporation issued \$280 million of Convertible Subordinated Notes. In July 2003, PG&E Corporation issued \$600 million of Senior Secured Notes.

CONTRACTUAL COMMITMENTS

The following table provides information about the Utility's and PG&E Corporation's contractual obligations and commitments at December 31, 2004. PG&E Corporation and the Utility enter into contractual obligations in connection with business activities. These obligations primarily relate to financing arrangements (such as long-term debt, preferred stock and certain forms of regulatory

financing), purchases of transportation capacity, natural gas and electricity to support customer demand and the purchase of fuel and transportation to support the Utility's generation activities.

	Payment due by period				
	Total	Less than One year	1-3 years	3-5 years	More than 5 years
	(in millions)				
Contractual Commitments:					
Utility					
Purchase obligations:					
Power purchase agreements ⁽¹⁾ :					
Qualifying facilities	\$ 18,733	\$ 1,566	\$ 3,144	\$ 2,899	\$ 11,124
Irrigation district and water agencies	573	77	113	114	269
Other power purchase agreements	295	94	140	39	22
Natural gas supply and transportation	960	829	131	—	—
Nuclear fuel	290	46	109	82	53
Preferred dividends and redemption requirements ⁽²⁾	165	15	83	67	—
Employee benefits:					
Pension ⁽³⁾	40	20	20	—	—
Postretirement benefits other than pension ⁽³⁾	130	65	65	—	—
Other commitments ⁽⁴⁾	132	109	21	2	—
Operating leases	73	14	27	18	14
	21,391	2,835	3,853	3,221	11,482
Long-term debt ⁽⁵⁾ :					
Fixed rate obligations	11,831	295	929	1,155	9,452
Variable rate obligations	2,257	805	1,452	—	—
Other long-term liabilities reflected on the Utility's balance sheet under GAAP:					
Rate reduction bonds	870	290	580	—	—
Capital lease	10	2	4	4	—
PG&E Corporation					
Purchase obligations:					
Purchase agreements—natural gas supply ⁽⁶⁾	176	—	2	22	152
Long-term debt ⁽⁵⁾ :					
Convertible subordinated notes	426	27	53	53	293
Other long-term debt	1	1	—	—	—
Operating leases	19	3	6	5	5

- (1) This table does not include DWR allocated contracts because the DWR is currently legally and financially responsible for these contracts or payments the Utility could be required to pay the ISO under the terms of a transmission control agreement which is discussed below.
- (2) Preferred dividend and redemption requirement estimates beyond 5 years do not include non-redeemable preferred stock dividend payments as these continue in perpetuity.
- (3) Contribution estimates include amounts required to fund a voluntary retirement program of approximately \$20 million annually in 2005 and 2006. PG&E Corporation's and the Utility's funding policy is to contribute tax deductible amounts, consistent with applicable regulatory decisions (including the 2003 GRC), sufficient to meet minimum funding requirements. Contribution estimates after 2006 will be driven by GRC decisions.

- (4) Includes commitments for capital infusion agreements for limited partnership interests in the aggregate amount of approximately \$11 million, contracts to retrofit generation equipment at the Utility's facilities in the aggregate amount of approximately \$38 million, load-control and self-generation CPUC initiatives in the aggregate amount of approximately \$73 million, contracts for local and long-distance telecommunications in the aggregate amount of approximately \$10 million and capital expenditures for which the Utility has contractual obligations or firm commitments.
- (5) Includes interest payments over life of debt. See Note 3 of the Notes to the Consolidated Financial Statements for further discussion.
- (6) See Note 12 of the Notes to the Consolidated Financial Statements for further discussion of assigned natural gas capacity contracts.

Contractual Commitments

Utility

The Utility's contractual commitments include power purchase agreements (including agreements with qualifying facilities, irrigation districts and water agencies and renewable energy providers), natural gas supply and transportation agreements, nuclear fuel agreements, operating leases and other commitments.

Power Purchase Agreements

Qualifying Facility Power Purchase Agreements —The Utility is required by CPUC decisions to purchase energy and capacity from independent power producers that are qualifying facilities under the Public Utility Regulatory Policies Act of 1978, or PURPA. To implement PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with qualifying facilities and approved the applicable terms, conditions, prices and eligibility requirements. These agreements require the Utility to pay for energy and capacity. Energy payments are based on the qualifying facility's actual electrical output and CPUC-approved energy prices, while capacity payments are based on the qualifying facility's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the qualifying facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

As of December 31, 2004, the Utility had agreements with 300 qualifying facilities for approximately 4,300 megawatts, or MW, that are in operation. Agreements for approximately 3,950 MW expire at various dates between 2005 and 2028. Qualifying facility power purchase agreements for approximately 350 MW have no specific expiration dates and will terminate only when the owner of the qualifying facility exercises its termination option. The Utility also has power purchase agreements with approximately 50 inoperative qualifying facilities. The total of approximately 4,300 MW consists of approximately 2,600 MW from cogeneration projects, 700 MW from wind projects and 1,000 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar and hydroelectric.

On January 22, 2004, the CPUC ordered the California investor-owned electric utilities to allow owners of qualifying facilities with certain power purchase agreements expiring before the end of 2005 to extend these contracts for five years with modified pricing terms. As of December 31, 2004, thirteen qualifying facilities had entered into such five-year contract extensions. Qualifying facility power purchase agreements accounted for approximately 23% of the Utility's 2004 electricity sources, approximately 20% of the Utility's 2003 electricity sources, and approximately 25% of the Utility's 2002 electricity sources. No single qualifying facility accounted for more than 5% of the Utility's 2004, 2003 or 2002 electricity sources.

There are proceedings pending at the CPUC that may impact both the amount of payments to qualifying facilities and the number of qualifying facilities holding power purchase agreements with the Utility. The CPUC will address whether certain payments for short-term power deliveries required by the power purchase agreements comply with the pricing requirements of the PURPA. The CPUC is also considering whether to require the California investor-owned electric utilities to enter into new power purchase agreements with existing qualifying facilities with expiring power purchase agreements and with newly-constructed qualifying facilities. PG&E Corporation and the Utility are unable to estimate the outcome of these proceedings.

In a proceeding pending at the CPUC, the Utility has requested refunds in excess of \$500 million for overpayments from June 2000 through March 2001 that were made to qualifying facilities pursuant to CPUC orders at approved rates. The net after-tax amount of any qualifying facilities refunds, which the Utility actually realizes in cash, claim offsets or other credits, would be credited to customers, either as a reduction to the principal amount of the second series of ERBs anticipated to be issued in November 2005, or if refunds are received after the second series of ERBs is issued, as a credit to the balancing account that tracks recovery of the customer costs and benefits related to the ERBs. PG&E Corporation and the Utility are unable to estimate the outcome of this proceeding.

Irrigation Districts and Water Agencies —The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts' and water agencies' debt service requirements, regardless if any hydroelectric power is supplied, and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2005 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 5% of the Utility's 2004 electricity sources, approximately 5% of the Utility's 2003 electricity sources and approximately 4% of the Utility's 2002 electricity sources.

Other Power Purchase Agreements

Electricity Purchases to Satisfy the Residual Net Open Position —In 2004 the Utility continued buying electricity to meet its residual net open position. During 2004, more than 10,000 Gigawatt hours, or GWh, of energy was bought and sold in the wholesale market to manage the 2004 residual net open position. Most of the Utility's contracts entered into in 2004 had terms of less than one year. In 2004, the Utility both submitted and requested bids in competitive solicitations to meet intermediate and long-term needs and anticipates procuring electricity under contracts with multi-year terms beginning in 2005.

Renewable Energy Requirement —California law requires that, beginning in 2003, each California retail seller of electricity, except for municipal utilities, must increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year, the annual procurement target, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. The Utility was excused from meeting its annual procurement target under the current law in 2003 and 2004 due to its Chapter 11 proceeding. With its exit from Chapter 11, as of January 1, 2005, the Utility is no longer exempt from complying with its annual procurement target. To meet the 20% goal by the end of 2017, the Utility estimates that it will need to purchase 700-800 GWh of electricity from renewable resources each year. During 2003 and 2004, the Utility entered into several new renewable power purchase contracts that will help the Utility meet its goals. The Utility also is conducting negotiations with several renewable energy providers pursuant to a request for offers made by the Utility in July 2004 that should result in the Utility entering into a number of new renewable contracts in 2005. In January 2005, the California Senate introduced a bill proposing to require the goal to be met by the end of 2010 instead of 2017. The CPUC also has suggested that the 20% goal be met by 2010. The Utility estimates that the accelerated goal would require the Utility to increase the amount of its annual renewable energy

purchases to approximately 800-900 GWh. Based on the medium load scenario in the Utility's long-term electricity procurement plan, the Utility believes that it can meet the accelerated goal.

Annual Receipts and Payments —The payments made under qualifying facility, irrigation district, water agency and bilateral agreements during 2002 through 2004 were as follows:

	2004	2003	2002
	(in millions)		
Qualifying facility energy payments	\$ 1,002	\$ 994	\$ 1,051
Qualifying facility capacity payments	487	499	506
Irrigation district and water agency payments	61	62	57
Other power purchase agreement payments	834	513	196

At December 31, 2004, the undiscounted future expected power purchase agreement payments were as follows:

	Qualifying Facility		Irrigation District & Water Agency		Other		Total
	Energy	Capacity	Operations & Maintenance	Debt Service	Energy	Capacity	
	(in millions)						
2005	\$ 1,060	\$ 506	\$ 51	\$ 26	\$ 53	\$ 41	\$ 1,737
2006	1,082	506	31	26	39	36	1,720
2007	1,070	486	30	26	29	36	1,677
2008	1,040	476	33	26	15	9	1,599
2009	947	436	31	24	10	5	1,453
Thereafter	7,633	3,491	152	117	18	4	11,415
Total	\$ 12,832	\$ 5,901	\$ 328	\$ 245	\$ 164	\$ 131	\$ 19,601

Natural Gas Supply and Transportation Agreements

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers. The contract lengths and natural gas sources of the Utility's portfolio of natural gas procurement contracts has fluctuated, generally based on market conditions.

During the period that the Utility was in Chapter 11, the Utility used several different credit arrangements to purchase natural gas, including a \$10 million cash collateralized standby letter of credit and a pledge of its core natural gas customer accounts receivable. In connection with its emergence from Chapter 11, the Utility received investment grade issuer credit ratings from Moody's and S&P. As a result of these credit rating upgrades, the Utility has obtained unsecured credit lines from the majority of its gas supply counterparties.

At December 31, 2004, the Utility's obligations for natural gas purchases and gas transportation services were as follows:

	(in millions)
2005	\$ 829
2006	124
2007	7
2008	—
2009	—
Thereafter	—
Total	\$ 960

Payments for natural gas purchases and gas transportation services amounted to approximately \$1.8 billion in 2004, \$1.5 billion in 2003, and \$898 million in 2002.

Nuclear Fuel Agreements

The Utility has purchase agreements for nuclear fuel. These agreements have terms ranging from two to eight years and are intended to ensure long-term fuel supply. Deliveries under 9 of the 11 contracts in place at the end of 2003 were completed by 2004. New contracts for deliveries in 2005 to 2012 are under negotiation. In most cases, the Utility's nuclear fuel contracts are requirements-based. The Utility relies on large, well-established international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms also are diversified, ranging from fixed prices to market-based prices to base prices that are escalated using published indices.

At December 31, 2004, the undiscounted obligations under nuclear fuel agreements were as follows:

	(in millions)
2005	\$ 46
2006	54
2007	55
2008	50
2009	32
Thereafter	53
Total	<u>\$ 290</u>

Payments for nuclear fuel amounted to approximately \$119 million in 2004, \$57 million in 2003 and \$70 million in 2002.

Reliability Must Run Agreements

The ISO has entered into reliability must run, or RMR, agreements with various power plant owners, including the Utility, that require designated units in certain power plants, known as RMR plants, to remain available to generate electricity upon the ISO's demand when needed for local transmission system reliability. At December 31, 2004, as a party to the Transmission Control Agreement, or the TCA, the Utility estimated that it could be obligated to pay the ISO approximately \$570 million in costs incurred under these RMR agreements during the period January 1, 2005 to December 31, 2006. Of this amount, the Utility estimates that it would receive approximately \$42 million under its RMR agreements during the same period. These costs and revenues are subject to applicable ratemaking mechanisms.

In June 2000, a FERC administrative law judge, or ALJ, issued an initial decision addressing subsidiaries of Mirant Corporation. The decision approved rates and a ratemaking methodology that, if affirmed by the FERC, will require the Mirant subsidiaries that are parties to three RMR agreements with the ISO to refund to the ISO, and the ISO to refund to the Utility, excess payments of approximately \$360 million, including interest, for the availability of Mirant's RMR plants under these agreements. On July 14, 2003, Mirant filed a petition for reorganization under Chapter 11 and on December 15, 2003, the Utility filed claims in Mirant's Chapter 11 proceeding, including a claim for an RMR refund. On January 14, 2005, the Utility entered into a settlement with Mirant and its subsidiaries that own RMR units that will resolve the Utility's claim through September 30, 2004. The settlement agreement is subject to approval by the FERC, the bankruptcy court overseeing the Chapter 11 cases filed by Mirant and these subsidiaries, and, to the extent deemed necessary by the Utility, by the bankruptcy court that retains jurisdiction over the Utility's Chapter 11 case. Under the settlement, Mirant will transfer to the Utility Mirant's interest in and equipment for the partially built Contra Costa Unit 8 power plant. If Contra Costa Unit 8 is not transferred to the Utility as a result of various

contingencies described in the settlement, Mirant will pay the Utility at least \$70 million in lieu of the plant assets. In addition, under the settlement, the Utility will enter into a contract that gives the Utility the right to dispatch power from certain RMR units owned by Mirant subsidiaries from 2006-2012, and the Utility will receive approximately \$60 million of allowed claims, credits, offsets, or cash from Mirant or its subsidiaries. The Utility is unable to predict whether and when the FERC or the bankruptcy courts will approve the settlement. Although the settlement resolves issues concerning any refund that might be owed by Mirant, it does not address the underlying merits of the RMR case, which will still be decided by the FERC.

In November 2001, after the ALJ issued the initial decision in Mirant's rate case, two complaints were filed at the FERC against other RMR plant owners, including the Utility, alleging that the ratemaking methodology approved in the ALJ's initial decision should be applied to the other RMR agreements. The complainants asked the FERC to take no action until after the FERC issues its final decision in Mirant's rate case. If the FERC adopts the ALJ's decision in the Mirant rate case and applies the ratemaking methodology to the Utility's RMR plants, the Utility could be required to refund payments it received from the ISO for the availability of the Utility's RMR plants. The Utility has responded to the complaint asserting that the methodology approved in the ALJ's decision should not apply to the Utility. The FERC has not yet acted on these complaints. On December 23, 2004, the Utility filed a settlement with all the complainants that, if approved by FERC, will result in the withdrawal of the complaint with no decision by the FERC on its merits. If the case is not dismissed, the Utility believes the ultimate outcome of this matter will not have an adverse material effect on the Utility's results of operations or financial condition.

Other Commitments and Operating Leases

The Utility has other commitments relating to operating leases, capital infusion agreements, equipment replacements, the self-generation incentive program exchange agreements and telecommunication contracts. At December 31, 2004, the future minimum payments related to other commitments were as follows:

	(in millions)
2005	\$ 123
2006	31
2007	17
2008	14
2009	6
Thereafter	14
Total	\$ 205

Payments for other commitments amounted to approximately \$111 million in 2004, \$74 million in 2003, and \$34 million in 2002.

Financing Commitments

The Utility's current commitments under financing arrangements include obligations to repay First Mortgage Bonds, pollution control bond-related agreements, credit facilities and reimbursement agreements associated with letters of credit.

In addition, PG&E Funding, LLC must make scheduled payments on its rate reduction bonds. The balance owed on these bonds at December 31, 2004 was approximately \$870 million. Annual principal payments on the rate reduction bonds total approximately \$290 million. The rate reduction bonds are expected to be fully retired by the end of 2007.

A detailed description of these commitments is included in Note 3 and Note 4 of the Notes to the Consolidated Financial Statements.

CAPITAL EXPENDITURES

The Utility's investment in plant and equipment totaled approximately \$1.6 billion in 2004, \$1.7 billion in 2003 and \$1.5 billion in 2002. The Utility's annual capital expenditures are expected to increase to an average of approximately \$2.0 billion annually over the next five years. These expenditures are necessary to replace aging and obsolete equipment and accommodate anticipated electricity and natural gas load growth of approximately 2% and 1.2% per year, respectively. Capital expenditures for which contracts or firm commitments exist have, in addition to being included in estimated capital expenditures, been included in the "Contractual Commitments" table above, which details the Utility's contractual obligations and commitments at December 31, 2004. The estimate of capital expenditures over the next five years includes the following significant capital expenditure projects:

- New customer connections and expansion of the existing electricity and natural gas distribution systems anticipated to average approximately \$400 million annually over the next five years;
- Replacements and upgrades to portions of the Utility's electricity distribution system anticipated to average approximately \$400 million annually over the next five years;
- Replacement of natural gas distribution pipelines expected to average approximately \$70 million annually over the next five years;
- Replacements and capacity expansion of the electricity transmission system expected to average approximately \$400 million annually over the next five years;
- Replacements and upgrades to the Utility's natural gas transportation facilities expected to average approximately \$120 million annually over the next five years;
- Replacements and upgrades of existing facilities at the Utility's Diablo Canyon power plant, including the turbine and steam generator replacement projects, potential investments in a new combined cycle generation unit in Contra Costa County that may be acquired pursuant to a settlement agreement with Mirant, and replacements, upgrades and relicensing of the Utility's hydroelectric generation facilities. All of these generation-related projects are expected to average approximately \$370 million annually over the next five years; and
- Investment in common plant, including computers, vehicles, facilities and communications equipment, expected to average approximately \$200 million annually over the next five years.

The Utility retains the ability to delay or defer substantial amounts of these planned expenditures in light of changing economic conditions and changing technology. It is also possible that these projects may be replaced by other projects. Consistent with past practice, the Utility expects that any capital expenditures will be included in its rate base and recoverable in rates. Based on the estimate of average capital expenditures of approximately \$2.0 billion annually over the next five years, the Utility's average annual rate base would grow by approximately 4.5% per year over the five-year period.

The Utility's residual net open position is expected to increase over time. To meet this need, the Utility will need to enter into contracts with third-party generators for additional supplies of electricity, develop or otherwise acquire additional generation facilities or satisfy its residual net open position through a combination of the two. The discussion above does not include any capital expenditures for new generation facilities aside from the Contra Costa project described above. The discussion above also does not include any capital expenditures necessary to implement advanced metering improvements.

The estimate of capital expenditures discussed above does not include up to \$2.0 billion in additional potential expenditures over the 2005 through 2009 period for:

- New generation facilities to comply with the Utility's long-term electricity procurement plan as approved by the CPUC. To meet future resource needs, the Utility will need to enter into contracts with third-party generators for additional supplies of electricity, develop or otherwise acquire additional generation facilities;
- Electric transmission projects to accommodate system expansions approved by the ISO, interconnections and upgrades triggered by new generation, costs to extend the life of or replace transmission equipment;
- Implementation of electric distribution reliability and technology driven service enhancements such as advanced metering; and
- Reliability and service enhancements of the Utility's gas distribution infrastructure to provide access to new natural gas sources.

The Utility has estimated that if these additional capital expenditures related to new generation, electric transmission and distribution and gas distribution are made, the Utility's total weighted average rate base would grow by approximately 6.5% over the five-year period.

Advanced Metering Improvements

The CPUC is assessing the viability of implementing an advanced metering infrastructure for residential and small commercial customers. This infrastructure would enable the California investor-owned electric utilities to measure usage of electricity on a time-of-use basis and to charge demand responsive rates. The goal of demand responsive rates is to encourage customers to reduce energy consumption during peak demand periods and reduce peak period procurement costs. Advanced meters can record usage in time intervals and be read remotely. The Utility is implementing demand responsive tariffs for large industrial customers who already have advanced metering systems in place, and has just completed the second year of a statewide pilot program designed to test whether and how much residential and small commercial customers will respond to demand responsive rates. The Utility expects to provide information to the CPUC in the first quarter of 2005 regarding the results of this pilot program. If the CPUC determines that it would be cost-effective to install advanced metering on a large-scale and authorizes the Utility to proceed with large scale development of advanced metering for residential and small commercial customers, the Utility expects that it would incur substantial costs to convert its meters, build the meter reading network, and build the data storage and processing facilities to bill its customers. The Utility would expect to recover through rates the capital investments and any ongoing operating costs associated with implementing the advanced metering improvements. The total deployment of an advanced metering infrastructure to all of the Utility's electricity and natural gas customers using equipment and technology currently available may cost more than \$1.0 billion, based on a five-year installation schedule starting in 2006.

OFF-BALANCE SHEET ARRANGEMENTS

For financing and other business purposes, PG&E Corporation and the Utility utilize certain arrangements that are not reflected in their Consolidated Balance Sheets. Such arrangements do not represent a significant part of either PG&E Corporation's or the Utility's activities or a significant ongoing source of financing. These arrangements are used to enable PG&E Corporation or the Utility to obtain financing or execute commercial transactions on favorable terms. For further information related to letter of credit agreements, the credit facilities, aspects of PG&E Corporation's accelerated share repurchase program and PG&E Corporation's guarantee related to certain NEGT indemnity obligations, see Notes 3, 6 and 12 of the Notes to the Consolidated Financial Statements. Amounts due

under these contracts are contingent upon terms contained in these agreements and are not included in the table of contractual commitments above.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies that are discussed below and in Note 12 to the Notes to the Consolidated Financial Statements.

FERC Proceedings

Various entities, including the Utility and the state of California are seeking up to \$8.9 billion in refunds for electricity overcharges on behalf of California electricity purchasers for the period May 2000 to June 2001 through a proceeding pending at the FERC. This proceeding, the Refund Proceeding, commenced on August 2, 2000 when a complaint was filed against all suppliers in the ISO and PX markets. On July 25, 2001, the FERC held that refunds would be available for certain overcharges, and established a process to determine the refunds but asserted that it could not order market-wide refunds for periods before October 2, 2000. In December 2002, a FERC ALJ issued an initial decision in the Refund Proceeding finding that power suppliers overcharged the utilities, the state of California and other buyers approximately \$1.8 billion from October 2, 2000 to June 20, 2001, but that California buyers still owe the power suppliers approximately \$3.0 billion, leaving approximately \$1.2 billion in net unpaid bills.

In March 2003, the FERC confirmed most of the ALJ's findings in the Refund Proceeding, but partially modified the refund methodology to include use of a new natural gas price methodology as the basis for mitigated prices. The FERC indicated that it would consider later allowances claimed by sellers for natural gas costs above the natural gas prices in the refund methodology. The FERC directed the ISO and the PX (which operates solely to reconcile remaining refund amounts owed) to make compliance filings establishing refund amounts. The ISO has indicated that it plans to make its compliance filing during the first half of 2005 with the PX to follow. In October 2003, the FERC affirmed its March 2003 decision and various parties appealed to the Ninth Circuit. Briefs have been submitted concerning which power suppliers are subject to refunds, the appropriate time period for which refunds can be ordered, and which transactions are subject to refunds. These matters will be argued before the Ninth Circuit on April 12 and 13, 2005, and a decision is expected in the following months.

The final refunds will not be determined until the FERC issues a final decision in the Refund Proceeding, following the ISO and PX compliance filings and the resolution of the appeals of the FERC's orders. In addition, future refunds could increase or decrease as a result of retroactive adjustments proposed by the ISO, which incorporate revised data provided by the Utility and other entities.

In the FERC's separate proceedings to investigate whether tariff violations occurred in the period before October 2, 2000, the FERC has asserted that it has the power to order power suppliers to disgorge any profits if the FERC finds that the tariffs in force at that time were violated or subject to manipulation. In September 2004, the Ninth Circuit found that the FERC has the authority to provide refunds for tariff violations involving inadequate transaction reporting for sales into the California spot markets throughout the period before October 2, 2000. The FERC has not yet acted on this finding and it is uncertain how it will be applied by the FERC.

The Utility recorded approximately \$1.8 billion of claims filed by various electricity generators in its Chapter 11 proceeding as liabilities subject to compromise. This amount is subject to a pre-petition offset of approximately \$200 million, reducing the net liability recorded to approximately \$1.6 billion. Under a bankruptcy court order, the aggregate allowable amount of ISO, PX and generator claims was limited to approximately \$1.6 billion. The Utility currently estimates that the claims would have been reduced to approximately \$1.0 billion based on the refund methodology recommended in the FERC ALJ's initial decision. The revised methodology adopted by the FERC's March 2003 decision could

further reduce the amount by several hundred million dollars, offset by the amount of any additional fuel cost allowance for suppliers.

The Utility has entered into settlements with various power suppliers resolving the Utility's claims against these power suppliers. As discussed in Note 1 of the Notes to the Consolidated Financial Statements, as of December 31, 2004, the Utility has recorded offsets to the Settlement Regulatory Asset of approximately \$309 million, pre-tax (\$183 million, after-tax) in connection with settlements. The final net after-tax amount of any amounts received by the Utility under future settlements with energy suppliers will be credited to customers, either as a reduction to the principal amount of the second series of ERBs, anticipated to be issued in November 2005, or if refunds are received after the second series of ERBs is issued, as a credit to the balancing account that tracks recovery of the customer costs and benefits related to the ERBs.

As discussed in Note 13 of the Notes to the Consolidated Financial Statements, in January 2005, the Utility and other parties entered into a settlement agreement with Mirant Corporation and its subsidiaries, to resolve Mirant's liability for FERC refunds, penalties and civil liabilities arising out of the California energy crisis. The settlement agreement is subject to approval by the FERC, the bankruptcy court overseeing Mirant's bankruptcy proceedings, and to the extent deemed necessary by the Utility, the bankruptcy court that retains jurisdiction over the Utility's Chapter 11 case. Although settlement discussions with a number of other major sellers and other market participants are continuing, the Utility cannot predict whether these settlement negotiations will be successful.

REGULATORY MATTERS

This section of MD&A discusses significant regulatory issues pending before the CPUC, the FERC, or the NRC, the resolution of which may affect the Utility's and PG&E Corporation's results of operations or financial condition.

Electricity and Natural Gas Distribution and Electricity Generation

The Utility's primary base revenue requirement proceeding is the general rate case filed with the CPUC. In the general rate case, the CPUC authorizes the amount the Utility can collect from customers to recover its basic business and operational costs for electricity and natural gas distribution and electricity generation operations. The general rate case typically sets the annual revenue requirement levels for a three-year rate period.

2003 General Rate Case

In May 2004, the CPUC issued a decision in the Utility's 2003 GRC. The decision approved the July 2003 and September 2003 settlement agreements reached among the Utility and various consumer groups to set the Utility's 2003 base revenue requirements at approximately:

- \$2.5 billion for electricity distribution operations, representing a \$236 million increase over the previously authorized amount;
- \$912 million for electricity generation operations, representing a \$38 million increase over the previously authorized amount; and
- \$927 million for natural gas distribution operations, representing a \$52 million increase over the previously authorized amount.

As part of the GRC, the CPUC approved the following minimum and maximum yearly adjustments to the Utility's 2003 base revenue requirements, or attrition adjustments, for 2004, 2005, and 2006 based on the change in the CPI:

	2004	2005	2006
Electricity and Natural Gas Distribution			
Minimum	2.00%	2.25%	3.00%
Multiplier	Change in CPI	Change in CPI	Change in CPI+1%
Maximum	3.00%	3.25%	4.00%
Electricity Generation			
Minimum	1.50%	1.50%	2.50%
Multiplier	Change in CPI	Change in CPI	Change in CPI+1%
Maximum	3.00%	3.00%	4.00%

In addition, under the GRC decision, if the Utility forecasts a second refueling outage at Diablo Canyon in any one year, the electricity generation revenue requirement would be increased by \$32 million per refueling outage, adjusted for changes in the CPI in the manner described in the decision. Currently, the only forecasted second refueling outage during the period 2004 to 2006 occurred in 2004.

As a result of the approval of the 2003 GRC, during the second quarter of 2004, the Utility recorded various regulatory assets and liabilities associated with revenue requirement increases, recovery of retained generation assets and unfunded taxes, depreciation, and decommissioning. During the third and fourth quarters of 2004, the Utility recorded electricity and natural gas distribution and electricity generation revenues under the new revenue requirements as approved by the 2003 GRC. The net increase in revenue requirements and revenues related to the 2003 GRC on the Utility's 2004 results of operations, on a pre-tax basis, is as follows:

	Revenue Requirement Increase			
	2003	2004	Recognized in 2003	Recognized in 2004
	(in millions)			
Electricity revenue	\$ 273	\$ 277	\$ 268	\$ 282
Natural gas revenue	52	50	—	102
Electricity attrition	—	100	—	100
Natural gas attrition	—	19	—	19
Regulatory assets, net	(17)	158	—	141
Total	\$ 308	\$ 604	\$ 268	\$ 644

Because the Utility collected revenue subject to refund for electricity distribution and generation in 2003, but not for natural gas distribution, the impact of the 2003 GRC decision on the Utility's 2004 results of operations is different for each area.

For electricity distribution and generation, the Utility collected electricity revenue and surcharges subject to refund under the frozen rate structure in 2003. The amount of electricity revenue to be refunded in 2003 incorporated the impact of the electric portion of the GRC settlement, therefore this was recognized in net income in 2003. In 2004, the Utility recorded its electricity distribution and generation base revenue requirements under a cost-of-service ratemaking structure. Because the 2003 refund obligation already incorporated the impact of the GRC that related to fiscal 2003, the Utility recorded the increase related to 2004 in its 2004 results of operations of approximately \$382 million, including attrition.

For natural gas distribution, since the CPUC issued a final decision on the Utility's 2003 GRC in 2004, the Utility recorded both the 2003 revenue requirement increase and the 2004 revenue requirement increase in its 2004 results of operations of approximately \$121 million, including attrition.

In addition, as a result of the GRC decision, the Utility has recorded various regulatory assets and liabilities associated with the recovery of retained generation assets, unfunded taxes, depreciation, and decommissioning. The net impact of these items resulted in after-tax earnings of approximately \$84 million recorded in the Utility's 2004 results of operations. These assets and liabilities are reflected in the Utility's current rates and will be amortized over their respective collection periods.

Another phase of the GRC was established to address the Utility's response to the December 2002 storm and the Utility's reliability performance. In October 2004, the CPUC voted to approve certain storm response improvement initiatives as well as a reliability performance incentive mechanism for the years 2005 through 2007. Under the performance incentive mechanism the Utility could receive up to \$24 million each year depending on the extent to which the Utility exceeds the reliability performance

improvement targets, but could be required to pay a penalty of up to \$24 million a year depending on the extent to which it fails to meet the targets. The decision does not provide the Utility with additional revenues to meet the reliability standards, but does include a margin of error around the targets in order to mitigate potential penalties. PG&E Corporation and the Utility are unable to predict whether or not the Utility will incur a reward or penalty related to the performance incentive mechanism.

In addition, on November 9, 2004, The Utility Reform Network, a consumer group, or TURN, filed a motion in the 2003 GRC seeking an investigation into the Utility's billing and collection practices alleging that the Utility's failure to issue timely bills and reliance on estimated billing constituted "billing errors" under the Utility's tariffs. In the case of "billing errors," the Utility is prohibited under its tariffs from billing customers for more than three months usage. The Utility responded to TURN's motion on December 30, 2004. On January 13, 2005, the CPUC adopted a resolution approving tariff changes stating that "billing error" includes failure to issue a bill and issuance of an estimated bill, under certain circumstances. The resolution stated that the tariff changes approved by the resolution "are consistent with existing CPUC policy, tariffs, and requirements." On February 17, 2005, the Utility filed an application for rehearing of this resolution with the CPUC on the basis that the resolution's characterization of the revised "billing error" definition as consistent with "existing CPUC policy, tariffs, and requirements," is contrary to both the plain language of the Utility's prior tariffs and the CPUC's own policies and requirements interpreting the Utility's prior tariffs. Although PG&E Corporation and the Utility are unable to predict whether TURN's motion for an investigation will be granted, PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse effect on PG&E Corporation's or the Utility's results of operations or financial condition.

2007 General Rate Case

The Utility's next GRC will be the 2007 GRC. The 2007 GRC will set the base revenue requirements for the years 2007 through 2009. The Utility plans to file its application for the 2007 GRC with the CPUC during the fourth quarter of 2005 with a final decision expected from the CPUC by the end of 2006. PG&E Corporation and the Utility are unable to predict what amount of revenue requirements the CPUC will authorize for the 2007 through 2009 period, when a final decision in this proceeding will be received, or the impact it will have on their financial condition or results of operations.

Cost of Capital Proceedings

The CPUC determines the rate of return that the Utility may earn on its electricity and natural gas distribution, natural gas transmission and storage, and electricity generation assets. In December 2004, the CPUC issued a final decision approving a return on common equity, or ROE, for the Utility of 11.22% for 2004 and 2005, which is consistent with the Settlement Agreement. The Settlement Agreement provides that from January 1, 2004 until certain credit ratings are achieved, the Utility's authorized ROE will be no less than 11.22% per year. The Settlement Agreement also provides that the authorized equity ratio of the Utility's capital structure for ratemaking purposes will not be less than 52%, except that for 2004 and 2005 it may not be less than 48.6%. The decision authorizes the following cost of capital for 2004 and 2005:

	2004			2005		
	Cost	Capital Structure	Weighted Cost	Cost	Capital Structure	Weighted Cost
Long-term debt	5.90%	48.2%	2.84%	6.10%	45.5%	2.78%
Preferred stock	6.76%	2.8%	0.19%	6.42%	2.5%	0.16%
Common equity	11.22%	49.0%	5.50%	11.22%	52.0%	5.83%
Return on rate base			8.53%			8.77%

The Utility's annual revenue requirement for 2004 decreased by approximately \$105 million compared to the CPUC last authorized revenue requirement, as a result of interest savings associated with the Utility's Chapter 11 exit financing. This decision did not have an impact on the Utility's financial results for 2004 because the Utility has adjusted its operating revenues for the difference between its last authorized rate of return on rate base of 9.24% in 2003 and the lower rate of return on rate base of 8.53% in 2004 that has now been approved.

Electricity Generation Resources

California legislation has been enacted which allows the Utility to recover its reasonably incurred wholesale electricity procurement costs and includes a mandatory rate adjustment provision that requires the CPUC to adjust rates on a timely basis to ensure that the Utility recovers its costs.

Procurement Cost Balancing Account and Mandatory Rate Adjustments

Effective January 1, 2003, as authorized by California law, the Utility established a balancing account, the Energy Resource Recovery Account, or ERRA, designed to track and allow recovery of the difference between the authorized revenue requirement and actual costs incurred under the Utility's authorized procurement plans, excluding the costs associated with the DWR allocated contracts and certain other items. The CPUC must review the revenues and costs associated with an investor-owned utility's electricity procurement plan at least semi-annually and adjust retail electricity rates or order refunds, as appropriate, when the forecast aggregate over-collections or under-collections exceed 5% of the utility's prior year electricity procurement revenues, excluding amounts collected for the DWR. The Utility's ERRA trigger threshold for 2004 is \$191 million. As of December 31, 2004, the ERRA had an under-collected balance of approximately \$75 million, which is below the 5% trigger for mandatory adjustment of rates. The CPUC approved an ERRA revenue requirement of \$2.189 billion for 2004. In its 2005 ERRA application filed in June 2004, the Utility requested a forecast revenue requirement of \$2.140 billion and the authority to amortize routine over and under-collections in the ERRA annually to coincide with January 1 rate changes. In December, 2004, the CPUC approved the Utility's Annual Electric True-up filing, under which the under-collections and over-collections in the Utility's electric-related balancing accounts, including the under-collection in the ERRA, are authorized to be recovered in the Utility's 2005 electric rates. A final decision on the 2005 ERRA application is expected in the first quarter of 2005.

The CPUC performs periodic compliance reviews of the procurement activities recorded in ERRA to ensure that the Utility's procurement activities are in compliance with its approved procurement plan. If the CPUC determines that the Utility's procurement activities were not in compliance with its approved procurement plan, some of the Utility's procurement costs could be disallowed. Procurement activities related to DWR allocated contracts could be disallowed up to a maximum of two times the Utility's administration costs associated with procurement, or \$36 million for 2004. The Utility and the CPUC's Office of Ratepayer Advocates, or the ORA, have agreed that there should be no disallowances in the Utility's ERRA proceeding reviewing procurement activities during the period from January 1, 2003 through December 31, 2003, and have jointly recommended that the CPUC close the record period. PG&E Corporation and the Utility are unable to predict whether a disallowance will result or the size of any potential disallowance. In addition, it is uncertain whether the CPUC will modify or eliminate the maximum disallowance for future years.

New Long-Term Generation Resource Commitments

As discussed in the "Overview" section above, in December 2004, the CPUC issued a final decision which approved, with certain modifications, each investor-owned electric utility's LTPP in order to authorize each utility to plan for and procure the resources necessary to provide reliable service to their customers for the ten-year period 2005-2014. The decision recognizes that each utility will have capacity needs over the ten-year period, especially in 2011 when most of the electricity

purchase contracts entered into by the DWR expire. In January 2005, several parties submitted applications for rehearing of the December 2004 CPUC decision. The Utility is unable to predict how or when the CPUC will respond to those applications.

In the LTPP filing the Utility assumed, under a medium load scenario, that:

- By 2014, its procurement responsibility would be reduced by approximately 4,000 megawatts, or MW; and
- Power plants currently providing 2,000 MW of generation to the Utility would retire within the next five or six years.

In addition, the LTPP reflects that all California investor-owned electric utilities are required to achieve an electricity planning reserve margin of 15% to 17% in excess of peak capacity electricity requirements by June 1, 2006.

The CPUC may require the Utility, or the Utility may elect, to satisfy all or a part of the resources necessary to meet their customers' energy needs by developing or acquiring additional generation facilities or by entering into long-term power purchase agreements. The December 2004 CPUC decision requires the utilities to solicit bids from providers of all potential sources of new generation (e.g., conventional or renewable resources to be provided under utility owned projects or turnkey developments, or buyouts, or under third party power purchase agreements) through a single, open, transparent and competitive request for offers, or RFO, process, although a utility can tailor a RFO to meet specific resource needs. The CPUC requires the utilities to use an independent evaluator to review the RFO process. Before the CPUC decision was issued, the CPUC had approved the Utility's solicitation of offers for utility-owned generation development and for generation to be provided under long-term power purchase agreements for approximately 1,200 MW of peaking resources by 2008 and an additional 1,000 MW of load-following resources by 2010. The Utility issued two RFOs in November 2004 for these resources. In order to incorporate elements of the CPUC's December 2004 decision, the Utility notified bidders on January 7, 2005 that it was deferring its RFOs to evaluate how to incorporate new RFO requirements adopted by the CPUC. The Utility expects to issue updated RFOs in March 2005 and request initial bids to be submitted in April 2005. It is anticipated that contracts for the winning bidders would be submitted to the CPUC for approval in the second half of 2005. Completed projects could result in rate base additions in 2008.

To help assure recovery of the Utility's cost of new long-term resource commitments, the CPUC adopted a non-bypassable charge to be collected from all customers on whose behalf the Utility makes these new commitments, including those who subsequently receive generation from other load-serving entities.

In addition, in its decision approving the LTPP, the CPUC recognized that credit rating agencies will consider obligations under long-term procurement contracts to have debt-like characteristics that will adversely affect the Utility's credit ratios, which may, in turn, adversely affect the resulting credit ratings. The CPUC has agreed that it will consider the debt equivalence impact of procurement contracts on credit ratings in future cost of capital proceedings. The Utility is required to employ S&P's method for assessing the debt equivalence of power purchase agreements when evaluating bids in an all-source solicitation, except that the debt equivalence factor should be 20% instead of 30%. As the Utility enters into contracts with counterparties, the Utility will be exposed to the risk that counterparties will fail to perform and associated business credit risks.

The CPUC also determined that for utility-owned generation resources, the utilities are prohibited from recovering initial capital costs in excess of their final bid price. If final project costs are less than the final bid price, the savings would be shared with customers, while any cost overruns would be absorbed by the utilities. Costs of future plant additions and annual operating and maintenance costs and similar costs incurred by a utility would be eligible for cost-of service ratemaking treatment.

If the Utility is not able to recover a material part of the cost of developing or acquiring additional generation facilities in rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

Renewable Energy

California law requires that, beginning in 2003, each California retail seller of electricity, except for municipal utilities, must increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year, the annual procurement target, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. In January 2005, the California Senate introduced a bill proposing to require the goal to be met by the end of 2010 instead of 2017. The CPUC also has suggested that the 20% goal be met by 2010. The Utility estimates that the accelerated goal would require the Utility to increase the amount of its annual renewable energy purchases to approximately 800-900 GWh. Based on the medium load scenario in the Utility's long-term electricity procurement plan, the Utility believes that it can meet the accelerated goal.

DWR Allocated Contracts

The Utility acts as a billing agent for the collection of the DWR's revenue requirements from the Utility's customers. The DWR's revenue requirements consist of a power charge to pay for the DWR's costs of purchasing electricity under its contracts and a bond charge to pay for the DWR's costs associated with its \$11.3 billion bond offering completed in November 2002. In December 2004, the CPUC issued a decision on the permanent cost allocation methodology for the DWR's power charge revenue requirements in 2004 and subsequent years, among the three California investor-owned electric utilities. The Utility's customers' share of 2004 DWR power charge revenue requirement is approximately \$1.7 billion after consideration of the DWR power charge adjustment to implement this decision. The Utility's customers' share of 2004 DWR bond charge revenue requirement is approximately \$369 million. In January 2005, the CPUC granted limited rehearing of its permanent cost allocation decision to address how to calculate the above-market costs of the DWR power contracts. A final decision on DWR permanent cost allocation is expected in the first quarter of 2005. The Utility cannot predict the final outcome of this matter. As a result of the transition from frozen rates and the electricity procurement recovery mechanism described below, the collection of DWR revenue requirements, or any adjustments thereto, should not affect the Utility's results of operations.

Electric Restructuring Costs Account Application

On April 16, 2004, the Utility filed an updated Electric Restructuring Costs Account application for recovery of distribution related electric industry restructuring related revenue requirements totaling \$117 million for the period 1999 through 2002. The Utility requested that the \$117 million revenue requirement increase become effective January 1, 2005, and be recovered through future rates charged to customers. Revenue requirements associated with these ongoing activities in 2003 and afterwards are included in the 2003 GRC.

On December 2, 2004, the CPUC adopted a proposed settlement agreement to resolve issues in this proceeding filed by the Utility, ORA, Aglet Consumer Alliance, and TURN. Under the settlement agreement, the Utility is authorized to collect \$80 million in revenue requirements to recover the distribution related electric industry restructuring costs through rates charged to certain of the Utility's customers beginning January 1, 2005. Additionally, beginning January 1, 2007, the Utility is required to remove from rate base all remaining net plant in service associated with the Utility's capital plant at issue in this application, projected to be approximately \$30 million at the end of 2006. During the fourth quarter of 2004, the Utility recorded a net pre-tax regulatory asset of approximately \$50 million, resulting in an increase of approximately \$30 million in after-tax net income.

FERC Transmission Rate Cases

The Utility's electric transmission revenues and wholesale and retail transmission rates are subject to authorization by the FERC. In January and October 2003, the Utility filed applications with the FERC requesting authority to recover its annual electricity transmission retail revenue requirements for 2003 and 2004. During the third quarter of 2004, the FERC issued final orders on these applications, which did not have a material impact on the Utility's 2004 results of operations. The current approved rates will remain in effect until the Utility's next rate application. The Utility expects to file its next transmission owner rate case requesting approval of 2006 retail electric transmission revenue requirements in August 2005.

Diablo Canyon Steam Generator Replacement Projects

The Utility established a steam generated replacement project to replace turbines and steam generators and other equipment at the two nuclear operating units at the Diablo Canyon nuclear power plant. The Utility plans to replace Unit 2's steam generators in 2008 and replace Unit 1's steam generators in 2009. Because the fabrication of new steam generators requires a long lead-time, in August 2004 the Utility entered into contracts with Westinghouse Electric Company LLC, or Westinghouse, for the design, fabrication and delivery of eight steam generators. Under the contracts, the Utility must pay Westinghouse for all work done and pro-rated profit up to the time the contracts are completed or cancelled. The contracts require progress payments in line with actual expenditures for materials and work completed over the life of the contracts. The Utility is currently in negotiation for an installation contract for the new steam generators. The negotiation is expected to be completed by the end of February 2005. On January 25, 2005, a CPUC administrative law judge issued a proposed decision that would find the steam generator replacement project to be cost-effective and would authorize the Utility to recover the projected \$706 million capital cost of the project in rates with no after-the-fact reasonableness review if the total costs do not exceed \$706 million, and established a maximum project cost of \$815 million. If the project costs exceed \$706 million, or if the CPUC has reason to believe that the costs may be unreasonable regardless of the amount, the CPUC may conduct a reasonableness review of all costs. The proposed decision recommends that the Utility would be allowed to recover the revenue requirements related to the project in rates beginning on January 1 of the year following the commencement of commercial operations of each unit. The CPUC may act on the proposed decision at its meeting to be held on February 25, 2005. Assuming the CPUC approves the proposed decision, the Utility would make the capital expenditures required to maintain a 2008/2009 implementation schedule. It is expected that the CPUC will issue a final decision on whether to approve the project in September 2005, after considering the environmental impact review for the project. Expenditures on the project of approximately \$25 million are expected to be incurred through February 2005 when the CPUC's decision on cost effectiveness is expected and these are expected to grow to approximately \$70 million in September 2005 when the CPUC's final decision approving the project is expected. If the CPUC approves the project, the Utility estimates it would spend an additional \$10 million in the last quarter of 2005. If the CPUC does not approve the projects, then the Utility will terminate the contracts and seek to recover the project costs that it incurred before termination from customers through the abandoned project process.

Spent Nuclear Fuel Storage Proceedings

Under the Nuclear Waste Policy Act of 1982, the Department of Energy, or the DOE, is responsible for the permanent storage and disposal of spent nuclear fuel. The Utility has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from the Utility's nuclear power facilities. Under the Utility's contract with the DOE, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal would be 2018. At the projected level of operation for Diablo Canyon, the Utility's current facilities are able to store on-site all spent fuel produced through approximately 2007. The

NRC granted authorization in March 2004 to build an on-site dry cask storage facility to store spent fuel through approximately 2021 for Unit 1 and to 2024 for Unit 2. However, several intervenors in that proceeding filed an appeal of the NRC's decision with the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit. Oral arguments on that appeal are expected in the first quarter of 2005 with a decision anticipated in the second half of 2005. Construction of the on-site dry cask storage facility is expected to start in the second quarter of 2005 after grading permits are obtained from the County of San Luis Obispo. To provide another storage alternative in the event construction of the dry cask storage facility is delayed, the Utility has also requested that the NRC approve another storage option to install a temporary storage rack in each unit's existing spent fuel storage pool that would increase the on-site storage capability to permit the Utility to operate Unit 1 until 2010 and Unit 2 until 2011. If the Utility is unsuccessful in permitting and constructing the on-site dry cask storage facility, and is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2007 and until such time as additional spent fuel can be safely stored.

Annual Earnings Assessment Proceeding for Energy Efficiency Program Activities and Public Purpose Programs

In May 2004, 2003, 2002, 2001, and 2000, the Utility filed its annual applications with the CPUC claiming incentives totaling approximately \$110 million for past energy efficiency and public purpose program activities. These applications remain subject to verification and approval by the CPUC. PG&E Corporation and the Utility are unable to predict the ultimate outcome of this proceeding.

Natural Gas Supply and Transportation

In December 2004, the CPUC issued a final decision approving the Gas Accord III Settlement Agreement that sets the Utility's gas transmission and storage rates and market structure for a three-year term, commencing January 1, 2005. The decision extends the terms of a settlement agreement originally reached in 1997 called the Gas Accord. The CPUC has approved previous extensions of the Gas Accord. Under the terms of the recent decision, the Utility's revenue requirement has been set at \$427.4 million for 2005, \$435.5 million for 2006, and \$443.7 million for 2007. This is compared to an authorized revenue requirement for 2004 of \$416.9 million, adjusted for the CPUC's final decision in the cost of capital proceeding as discussed above. Under the Gas Accord, the Utility's gas transmission and storage facilities are operated on an open-access basis, thus allowing all eligible shippers to subscribe to gas transmission and storage services. In addition, the Utility assumes risk of not recovering its full natural gas transportation and storage costs since the Utility does not have a balancing account for over-collections or under-collections of natural gas transportation or storage revenues.

The original Gas Accord market structure included an incentive mechanism for recovery of core procurement costs, or the CPIM, which is used to determine the reasonableness of the Utility's costs of purchasing natural gas for its customers. Under the CPIM, costs that fall within a market-based tolerance band, which is currently 99% to 102% of the benchmark, are considered reasonable and fully recoverable in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in the Utility's customers' rates, and the Utility's customers receive three-fourths of the savings when the costs are below 99% of the benchmark.

In 2004, the CPUC ordered the Utility and other California natural gas utilities to submit proposals addressing how California's long-term natural gas needs should be met through contracts with interstate pipelines, new liquefied natural gas facilities, storage facilities and in-state production of natural gas. Proposals were submitted in February 2004. The CPUC issued a decision in September 2004, which authorizes the utilities to expand their portfolios to access gas from multiple gas producing basins, to negotiate reduced capacity, and to terminate expiring contracts. The decision also established a pre-approval process for utility interstate and Canadian pipeline capacity contracts. The

second phase of this proceeding will establish a process to consider the adoption of standardized operational balancing agreements to connect all new upstream gas pipelines that interconnect with the pipeline systems of San Diego Gas and Electric and Southern California Gas Company.

RISK MANAGEMENT ACTIVITIES

The Utility and PG&E Corporation, mainly through its ownership of the Utility, are exposed to market risk, which is the risk that changes in market conditions will adversely affect net income or cash flows. PG&E Corporation and the Utility face market risk associated with their operations, financing arrangements, the marketplace for electricity, natural gas, electricity transmission, natural gas transportation and storage, other goods and services, and other aspects of their business. PG&E Corporation and the Utility categorize market risks as price risk, interest rate risk and credit risk. The Utility actively manages market risks through risk management programs that are designed to support business objectives, reduce costs, discourage unauthorized risk-taking, reduce earnings volatility and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (*i.e.* , risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of energy and financial instruments, including forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

The Utility estimates fair value of derivative instruments using the midpoint of quoted bid and asked forward prices, including quotes from customers, brokers, electronic exchanges and public indices, supplemented by online price information from news services. When market data is not available, the Utility uses models to estimate fair value.

Price Risk

Convertible Subordinated Notes

PG&E Corporation currently has outstanding \$280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,655 shares of common stock of PG&E Corporation, at a conversion price of \$15.09 per share. The conversion price is subject to adjustment should a significant change occur in the number of PG&E Corporation's outstanding common shares. To date, the conversion price has not required adjustment. In addition, the terms of the Convertible Subordinated Notes entitle the note holders to participate in any dividends declared and paid on PG&E Corporation's common shares based on their equity conversion value.

In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," or SFAS No. 133, the dividend participation rights component is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and marked to market on PG&E Corporation's Consolidated Statements of Operations as a non-operating expense (in Other expense, net), and reflected at fair value on PG&E Corporation's Consolidated Balance Sheets as \$76 million of non-current liability (in Non-current liabilities—other) and \$15 million of current liability (in Current liabilities—other). At December 31, 2004, the total estimated fair value of the dividend participation rights component on a pre-tax basis was approximately \$91 million.

Electricity

The Utility relies on electricity from a diverse mix of resources, including third-party contracts, amounts allocated under DWR contracts and its own electricity generation facilities. In addition, the Utility purchases and sells electricity on the spot market and the short-term forward market (contracts with delivery times ranging from one hour ahead to one year ahead).

It is estimated that the residual net open position (the amount of electricity needed to meet the demands of customers, plus applicable reserve margins, that is not satisfied from the Utility's own generation facilities, purchase contracts or DWR contracts allocated to the Utility's customers) will change over time for a number of reasons, including:

- Periodic expirations of existing electricity purchase contracts, or entering into new electricity purchase contracts;
- Fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract;
- Changes in the Utility's customers' electricity demands due to customer and economic growth and weather, and implementation of new energy efficiency and demand response programs, community choice aggregation, and a core/noncore retail market structure;
- Planning reserve and operating requirements;
- The reallocation of the DWR power purchase contracts among California investor-owned electric utilities; and
- The acquisition, retirement or closure of Utility generation facilities.

In addition, unexpected outages at the Utility's generation facilities, or a failure to perform by any of the counterparties to electricity purchase contracts or the DWR allocated contracts, would immediately increase the Utility's residual net open position. The Utility expects to satisfy at least some of the residual net open position through new contracts. In December 2004, the CPUC approved, with certain modifications, the Utility's LTPP for the 2005 through 2014 period. The LTPP is detailed in the preceding "Regulatory Matters" section of this MD&A.

The Settlement Agreement provides that the Utility will recover its reasonable costs of providing utility service, including power procurement costs. In addition, California law requires that the CPUC review revenues and expenses associated with a CPUC-approved procurement plan at least semi-annually through 2006 and adjust retail electricity rates, or order refunds when there is an under or over-collection exceeding 5% of the Utility's prior year electricity procurement revenues, excluding the revenue collected on behalf of the DWR. In addition, the CPUC has established a maximum procurement disallowance of approximately \$36 million for the Utility's administration of the DWR contracts and least-cost dispatch. Adverse market price changes are not expected to impact the Utility's net income, while these cost recovery regulatory mechanisms remain in place. However, the Utility is at risk to the extent that the CPUC may in the future disallow transactions. Additionally, market price changes could impact the timing of the Utility's cash flows.

Nuclear Fuel

The Utility purchases nuclear fuel for Diablo Canyon through contracts with terms ranging from two to five years. These long-term nuclear fuel agreements are with large, well-established international producers in order to diversify its commitments and provide security of supply.

Nuclear fuel purchases are subject to tariffs of up to 8% on imports from certain countries. The Utility's nuclear fuel costs have not increased based on the imposed tariffs because the terms of the Utility's existing long-term contracts do not include these costs. However, these contracts expired at the end of 2004, and prices under new contracts may be higher as a result of such tariffs. In addition, because of an increase in U.S. demand for uranium compared with the domestic supply, uranium prices have been trending higher in 2005.

As the Utility replaces existing contracts ending in 2004, new higher priced uranium contracts will raise nuclear fuel costs. The Utility is expected to partially offset these higher prices by executing a portfolio of near- and long-term contracts for nuclear fuel components. These costs are recovered in

ERRA (see the "Electricity Resources" section of this MD&A); therefore, the changes in nuclear fuel prices are not expected to materially impact net income.

Natural Gas

The Utility generally enters into physical and financial natural gas commodity contracts from one to 30 months in length to fulfill the needs of its retail core customers. Changes in temperature cause natural gas demand to vary daily, monthly and seasonally. Consequently, significant volumes of gas may be purchased in the monthly and, to a lesser extent, daily spot market. The Utility's cost of natural gas purchased for its core customers includes the commodity cost, the cost of Canadian and interstate transportation and gas storage costs.

Under the CPIM, the Utility's purchase costs for a twelve month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the benchmark, are considered reasonable and are fully recovered in customers' rates. One-half of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive, in their rates, three-fourths of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or \$25 million. While this cost recovery mechanism remains in place, changes in the price of natural gas are not expected to materially impact net income.

Transportation and Storage

The Utility currently faces price and volumetric risk for the portion of intrastate natural gas transportation capacity that is not contracted under fixed reservation charges used by core customers. Non-core customers contract with the Utility for natural gas transportation and storage, along with natural gas parking and lending (market center) services. The Utility is at risk for any natural gas transportation and storage revenue volatility. Transportation is sold at competitive market-based rates within a cost-of-service tariff framework. There are significant seasonal and annual variations in the demand for natural gas transportation and storage services. The Utility sells most of its pipeline capacity based on the volume of natural gas that is transported by its customers. As a result, the Utility's natural gas transportation revenues fluctuate.

The Utility uses value-at-risk to measure the expected maximum change over a one-day period in the 18-month forward value of its transportation and storage portfolio. This calculation is based on a 95% confidence level, which means that there is a 5% probability that the portfolio will incur a change in value in one day at least as large as the reported value-at-risk. For example, if the value-at-risk is calculated at \$5 million, there is a 95% probability that if prices moved against current positions, the change in the value of the portfolio resulting from a one-day price movement would not exceed \$5 million. The value-at-risk provides an indication of the Utility's exposure to potential market conditions that could impact revenues based on one-day price changes. It is also a way to measure the effectiveness of hedge strategies on a portfolio.

The Utility's value-at-risk for its transportation and storage portfolio was approximately \$4 million at December 31, 2004 and approximately \$4 million at December 31, 2003. A comparison of daily values-at-risk is included in order to provide context around the one-day amounts. The Utility's high, low and average transportation and storage value-at-risk during 2004 were approximately \$6 million, \$2 million and \$4 million, respectively. The Utility's high, low and average transportation and storage value-at-risk during 2003 were approximately \$13 million, \$2 million and \$5 million, respectively.

Value-at-risk has several limitations as a measure of portfolio risk, including, but not limited to, underestimation of the risk of a portfolio with significant options exposure, mismatch of one-day liquidation period assumed in the value-at-risk methodology as compared to the longer term holding

period of the storage and transportation portfolio, and inadequate indication of the exposure of a portfolio to extreme price movements. In addition, value-at-risk does not measure intra-day risk from position changes nor does it measure volumetric uncertainty in the demand for pipeline services.

Due to the limitations of value-at-risk, the Utility enhanced the calculation methodology during the fourth quarter of 2004 to 1) capture uncertainty with respect to demand (volumetric uncertainty) for pipeline services, 2) reflect the market conditions in which the pipeline operates by increasing the holding period to 12 months, and 3) include the uncertainty associated with the option exposure in the pipeline portfolio.

The calculation of value-at-risk under this methodology is based on a 99% confidence level, which means that there is a 1% probability that the portfolio will incur a change in value at least as large as the modified value-at-risk. This value-at-risk measure provides an indication of the Utility's exposure to potential market conditions that could impact revenues based on changes in market prices and demand for pipeline services over the 12-month holding period. The value-at-risk calculated under this methodology was approximately \$35 million at December 31, 2004.

The Utility will calculate value-at-risk using the enhanced methodology on a prospective basis only, beginning January 1, 2005. For comparative purposes in 2005, the Utility will continue to report value-at-risk under the methodology formerly used in addition to value-at-risk calculated under the enhanced methodology.

Interest Rate Risk

Interest rate risk is the risk that changes in interest rates could adversely affect earnings or cash flows. Specific interest rate risks for PG&E Corporation and the Utility include the risk of increasing interest rates on variable rate obligations.

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. At December 31, 2004, if interest rates changed by 1% for all current variable rate debt held by PG&E Corporation and the Utility, the change would affect net income by an immaterial amount, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if customers or counterparties failed to perform their contractual obligations.

PG&E Corporation had gross accounts receivable of approximately \$2.2 billion at December 31, 2004 and approximately \$2.5 billion at December 31, 2003. The majority of the accounts receivable were associated with the Utility's residential and small commercial customers. Based upon historical experience and evaluation of then-current factors, allowances for doubtful accounts of approximately \$93 million at December 31, 2004 and approximately \$68 million at December 31, 2003 were recorded against those accounts receivable. In accordance with tariffs, credit risk exposure is limited by requiring deposits from new customers and from those customers whose past payment practices are below standard. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in northern and central California. However, material loss due to non-performance from these customers is not considered likely.

The Utility manages credit risk for its wholesale customers and counterparties by assigning credit limits based on an evaluation of their financial condition, net worth, credit rating and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored frequently and a detailed credit analysis is performed at least annually.

Credit exposure for the Utility's wholesale customers and counterparties is calculated daily. If exposure exceeds the established limits, the Utility takes immediate action to reduce the exposure or obtain additional collateral, or both. Further, the Utility relies heavily on master agreements that require security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

The Utility calculates gross credit exposure for each of its wholesale customers and counterparties as the current mark-to-market value of the contract (*i.e.* , the amount that would be lost if the counterparty defaulted today), plus or minus any outstanding net receivables or payables, before the application of credit collateral. During 2004, the Utility recognized no material losses due to contract defaults or bankruptcies. At December 31, 2004, there were three counterparties that represented greater than 10% of the Utility's net wholesale credit exposure. Of these three counterparties, two were investment grade representing a total of approximately 47% of the Utility's net wholesale credit exposure and one was below investment grade representing approximately 17% of the Utility's net wholesale credit exposure.

The Utility conducts business with wholesale counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. This concentration of counterparties may impact the Utility's overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions. Credit losses experienced as a result of electrical and gas procurement activities are expected to be recoverable from customers and are therefore, not expected to have a material impact on earnings.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies, due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

Regulatory Assets and Liabilities

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the cost of providing service. SFAS No. 71 applies to all of the Utility's operations except for the operations of a natural gas pipeline. During the first quarter of 2004, the Utility began reapplying SFAS No. 71 to its generation operations.

Under SFAS No. 71, regulatory assets represent capitalized costs that otherwise would be charged to expense under GAAP. These costs are later recovered through regulated rates. Regulatory liabilities are created by rate actions of a regulator that will later be credited to customers through the ratemaking process. Regulatory assets and liabilities are recorded when it is probable, as defined in SFAS No. 5, "Accounting for Contingencies," or SFAS No. 5, that these items will be recovered or

reflected in future rates. Determining probability requires significant judgment on the part of management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, CPUC and FERC administrative law judge proposed decisions, final regulatory orders and the strength or status of applications for regulatory rehearings or state court appeals. The Utility also maintains regulatory balancing accounts, which are comprised of sales and cost balancing accounts. These balancing accounts are used to record the differences between revenues and costs that can be recovered through rates.

If the Utility determined that it could not apply SFAS No. 71 to its operations or, if under SFAS No. 71 it could not conclude that it is probable that revenues or costs would be recovered or reflected in future rates, the revenues or costs would be charged to income in the period in which they were incurred. If it is determined that a regulatory asset is no longer probable of recovery in rates, then SFAS No. 71 requires that it be written off at that time. At December 31, 2004, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of approximately \$7.5 billion and regulatory liabilities (including current balancing accounts payable) of approximately \$4.4 billion.

Unbilled Revenues

The Utility records revenue as electricity and natural gas are delivered. A portion of the revenue recognized has not yet been billed. Unbilled revenues are determined by factoring an estimate of the electricity and natural gas load delivered with recent historical usage and rate patterns. At December 31, 2004, the Utility had recorded approximately \$550 million in unbilled revenues.

Environmental Remediation Liabilities

Given the complexities of the legal and regulatory environment regarding environmental laws, the process of estimating environmental remediation liabilities is a subjective one. The Utility records a liability associated with environmental remediation activities when it is determined that remediation is probable, as defined in SFAS No. 5, and the cost can be estimated in a reasonable manner. The liability can be based on many factors, including site investigations, remediation, operations, maintenance, monitoring and closure. This liability is recorded at the lower range of estimated costs, unless a more objective estimate can be achieved. The recorded liability is re-examined every quarter.

At December 31, 2004, the Utility's accrual for undiscounted environmental liability was approximately \$327 million. The Utility's undiscounted future costs could increase to as much as \$480 million if other potentially responsible parties are not able to contribute to the settlement of these costs or the extent of contamination or necessary remediation is greater than anticipated.

The accrual for undiscounted environmental liability is representative of future events that are likely to occur. In determining maximum undiscounted future costs, events that are possible but not likely are included in the estimation.

Asset Retirement Obligations

The Utility accounts for its nuclear generation and certain fossil generation facilities under SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143. SFAS No. 143 requires that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. Rate-regulated entities may recognize regulatory assets or liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and costs recovered through the ratemaking process.

There are uncertainties regarding the ultimate cost associated with retiring the assets the Utility has accounted for in accordance with SFAS No. 143. These include, but are not limited to changes in assumed dates of decommissioning, regulatory requirements, technology, cost of labor, materials, and equipment. At December 31, 2004, the Utility's estimated cost of retiring these assets is approximately \$1.3 billion.

Pension and Other Postretirement Plans

Certain employees and retirees of PG&E Corporation and its subsidiaries participate in qualified and non-qualified non-contributory defined benefit pension plans. Certain retired employees and their eligible dependents of PG&E Corporation and its subsidiaries also participate in contributory medical plans, and certain retired employees participate in life insurance plans (referred to collectively as other benefits). Amounts that PG&E Corporation and the Utility recognize as costs and obligations to provide pension benefits under SFAS No. 87, "Employers' Accounting for Pensions," and other benefits under SFAS No. 106, "Employers Accounting for Postretirement Benefits other than Pensions," are based on a variety of factors. These factors include the provisions of the plans, employee demographics and various actuarial calculations, assumptions and accounting mechanisms. Because of the complexity of these calculations, the long-term nature of these obligations and the importance of the assumptions utilized, PG&E Corporation's and the Utility's estimate of these costs and obligations is a critical accounting estimate.

Actuarial assumptions used in determining pension obligations include the discount rate, the average rate of future compensation increases and the expected return on plan assets. Actuarial assumptions used in determining other benefit obligations include the discount rate, the average rate of future compensation increases, the expected return on plan assets and the assumed health care cost trend rate. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary. While PG&E Corporation and the Utility believe the assumptions used are appropriate, significant differences in actual experience, plan changes or significant changes in assumptions may materially affect the recorded pension and other benefit obligations and future plan expenses.

In accordance with accounting rules, changes in benefit obligations associated with these assumptions may not be recognized as costs on the income statement. Differences between actuarial assumptions and actual plan results are deferred and are amortized into cost only when the accumulated differences exceed 10% of the greater of the projected benefit obligation or the market-value of the related plan assets. If necessary, the excess is amortized over the average remaining service period of active employees. As such, significant portions of benefit costs recorded in any period may not reflect the actual level of cash benefits provided to plan participants. PG&E Corporation's and the Utility's recorded pension expense totaled \$182 million in 2004, \$212 million in 2003 and \$43 million in 2002, in accordance with the provisions of SFAS 87. PG&E Corporation's and the Utility's recorded expense for other postretirement and benefit obligations totaled \$78 million in 2004, \$76 million in 2003 and \$50 million in 2002, in accordance with the provisions of SFAS 106. Under SFAS No. 71, regulatory adjustments have been recorded in the Consolidated Statements of Operations and Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension expense or income for accounting purposes and Utility pension expense or income for ratemaking, which is based on a funding approach. The CPUC has authorized the Utility to recover the costs associated with its other benefits for 1993 and beyond. Recovery is based on the lesser of the amounts collected in rates or the annual contributions on a tax-deductible basis to the appropriate trusts.

PG&E Corporation's and the Utility's funding policy is to contribute tax deductible amounts, consistent with applicable regulatory decisions (including the 2003 GRC), sufficient to meet minimum funding requirements. Based upon current assumptions and available information, PG&E Corporation and the Utility have not identified any minimum funding requirements related to its pension plans, excluding amounts required to fund a voluntary retirement program of approximately \$20 million

annually in 2005 and 2006. PG&E Corporation and the Utility have estimated funding requirements related to their postretirement benefit plans at approximately \$65 million annually in 2005 and 2006. Contribution estimates for the Utility's pension and postretirement benefit plans after 2006 will be driven by future GRC decisions.

Pension and other benefit funds are held in external trusts. Trust assets, including accumulated earnings, must be used exclusively for pension and other benefit payments. Consistent with the trusts' investment policies, assets are invested in U.S. equities, non-U.S. equities and fixed income securities. Investment securities are exposed to various risks, including interest rate, credit and overall market volatility risks. As a result of these risks, it is reasonably possible that the market values of investment securities could increase or decrease in the near term. Increases or decreases in market values could materially affect the current value of the trusts and, as a result, the future level of pension and other benefit expense.

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income projected returns were based on historical returns for the broad U.S. bond market. Equity returns were based primarily on historical returns of the S&P 500 Index. For the Utility Retirement Plan, the assumed return of 8.1% compares to a ten-year actual return of 9.5%.

The rate used to discount pension and other post-retirement benefit plan liabilities was based on a yield curve developed from the Moody's AA Corporate Bond Index at December 31, 2004. This yield curve has discount rates that vary based on the maturity of the obligations. The estimated future cash flows for the pension and other post retirement obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

	Increase (decrease) in assumption	Increase in 2004 Pension Cost	Increase in Projected Benefit Obligation at December 31, 2004
		(in millions)	
Discount rate	(0.5)%	\$ 40	\$ 584
Rate of return on plan assets	(0.5)%	32	—
Rate of increase in compensation	0.5%	25	124

The following reflects the sensitivity of postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

	Increase (decrease) in assumption	Increase in 2004 Postretirement Benefit Cost	Increase in Accumulated Benefit Obligation at December 31, 2004
		(in millions)	
Health care cost trend rate	0.5%	\$ 5	\$ 37
Discount rate	(0.5)%	2	84

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Share-Based Payment Transactions

In December 2004, the Financial Accounting Standards Board, or FASB, issued Statement No. 123 (revised December 2004), "Share-Based Payment," or SFAS No. 123R. SFAS No. 123R requires that the cost resulting from all share-based payment transactions be recognized in the financial statements and establishes a fair-value measurement objective in determining the value of such a cost. SFAS

No. 123R will be effective for the third quarter of 2005. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 123R on their Consolidated Financial Statements.

Inventory Costs

In December 2004, the FASB issued Statement No. 151, "Inventory Costs an amendment of ARB No. 43, Chapter 4", or SFAS No. 151. The guidance clarifies that the allocation of fixed production overhead to inventory is based on normal capacity. Abnormal amounts of idle facility, excess freight, handling costs and spoilage should be recognized as a current period charge. SFAS No. 151 will be effective January 1, 2006. The adoption of SFAS No. 151 is not expected to have a material effect on the financial position or results of operations of either PG&E Corporation or the Utility.

TAXATION MATTERS

The IRS has completed its audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns and has assessed additional federal income taxes of approximately \$79 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and currently is discussing these adjustments with the IRS' Appeals Office. PG&E Corporation does not expect final resolution of these appeals to have a material impact on its financial position or results of operations.

In the fourth quarter of 2003, PG&E Corporation made an advance payment to the IRS of \$75 million relating to the 1999 and 2000 audit. The IRS completed its audit of PG&E Corporation's 1999 and 2000 consolidated federal income tax returns during the third quarter of 2004. As a result of the completion of this audit, PG&E Corporation received a refund from the IRS of \$14 million in January of 2005.

The IRS is auditing PG&E Corporation's 2001 and 2002 consolidated federal income tax returns. In September 2004, the IRS issued notices of proposed adjustments that propose to disallow \$104 million of synthetic fuel credits claimed on these tax returns. In addition, the IRS has proposed to disallow abandonment losses deducted on the 2002 tax return related to certain NEGT assets. These assets were transferred to NEGT lenders in the third quarter of 2004. In addition, the IRS has challenged other deductions related to NEGT prior to its Chapter 11 filing. PG&E Corporation is disputing the IRS's proposed adjustments and will contest these disallowances if the IRS continues to assert its current position.

PG&E Corporation has accrued \$52 million associated with NEGT related tax liabilities. In addition, PG&E Corporation has accrued a \$41 million liability to cover potential tax obligations relating to non-NEGT issues raised in outstanding tax audits. The Utility has accrued \$62 million to cover potential tax obligations for outstanding tax audits. Considering these reserves, PG&E Corporation does not expect the resolution of these matters to have a material impact on its financial position or result of operations.

All IRS audits of PG&E Corporation's federal income tax returns prior to 1997 have been closed.

Prior to July 8, 2003, the date that NEGT filed for bankruptcy protection, PG&E Corporation recognized federal income tax benefits related to the losses of NEGT and its subsidiaries. However, after July 7, 2003, under the cost method of accounting PG&E Corporation has not recognized additional income tax benefits for financial reporting purposes with respect to the losses of NEGT and its subsidiaries even though it must continue to include NEGT and its subsidiaries in its consolidated income tax returns. After its equity ownership in NEGT was cancelled on the effective date of NEGT's plan of reorganization, PG&E Corporation no longer includes NEGT or its subsidiaries in its consolidated income tax returns. In addition, any remaining deferred tax assets related to NEGT or its subsidiaries, were reversed as discontinued operations in the Consolidated Statements of Operations at

the time PG&E Corporation's equity interest in NEGT was cancelled. See Note 5 of the Notes to the Consolidated Financial Statements for further discussion.

In addition to the reversal of deferred tax assets referred to above, and based on preliminary information provided by NEGT, PG&E Corporation anticipates paying approximately \$86 million of consolidated federal tax obligations. This includes federal income taxes on NEGT activities through the effective date of NEGT's plan of reorganization.

PG&E Corporation and NEGT have entered into a separate agreement under which they have agreed to take certain actions and cooperate with each other with respect to certain tax matters, including future tax returns and audits.

For the year ended December 31, 2003, PG&E Corporation increased its valuation allowances against certain state deferred tax assets related to NEGT or its subsidiaries due to the uncertainty of their realization. During this period, valuation allowances of approximately \$24 million were recorded in discontinued operations, and approximately \$5 million was recorded in accumulated other comprehensive loss. No valuation allowances were recorded in the three-month period ended December 31, 2003 or during 2004.

At December 31, 2003, PG&E Corporation had \$420 million of California net operating loss, or NOL. The California NOLs were fully utilized in 2004.

ADDITIONAL SECURITY MEASURES

Various federal regulatory agencies have issued guidance and the NRC has issued orders regarding additional security measures to be taken at various facilities, including generation facilities, transmission substations and natural gas transportation facilities. The guidance and the orders require additional capital investment and increased operating costs. However, neither PG&E Corporation nor the Utility believes that these costs will have a material impact on its respective consolidated financial position or results of operations.

ENVIRONMENTAL AND LEGAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established both to maintain and improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substances, these laws and regulations may require PG&E Corporation and the Utility to remove those substances or to remedy effects on the environment. Also, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 12 of the Notes to the Consolidated Financial Statements for further discussion.

RISK FACTORS

Risks Related to PG&E Corporation

PG&E Corporation could be required to contribute capital to the Utility or be denied distributions from the Utility to the extent required by the CPUC's determination of the Utility's financial condition.

In approving the formation as the holding company of the Utility, the CPUC imposed certain conditions, including an obligation by PG&E Corporation's Board of Directors to give "first priority" to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve and to operate in a prudent and efficient manner. The CPUC later issued decisions in which it adopted an expansive interpretation of PG&E Corporation's obligations under this condition, including the requirement that PG&E Corporation, as well as each of the holding companies of the other major California investor-owned electric utilities, "infuse the utility with all types of capital necessary for the utility to fulfill its obligation to serve." PG&E Corporation and the other holding companies of the other major California investor-owned electric utilities appealed these decisions. On

May 21, 2004, the California Court of Appeal issued an opinion finding that the CPUC has limited jurisdiction over the holding companies to enforce the conditions imposed by the CPUC on their formations, but that the CPUC's decision interpreting the capital requirements condition was not ripe for review. On September 1, 2004, the California Supreme Court denied PG&E Corporation's petition seeking review of the California Court of Appeal's finding that the CPUC had limited jurisdiction.

Pursuant to the terms of the Settlement Agreement, the CPUC agreed that, once the CPUC approval of the Settlement Agreement is no longer subject to appeal, it will release all claims against PG&E Corporation and the Utility related to past holding company actions during the California energy crisis. Nevertheless, as now interpreted by the CPUC, whenever the Utility's financial health is impaired in the future, PG&E Corporation could be required to infuse the Utility with all types of capital necessary to fulfill its obligation to serve or to operate in a prudent and efficient manner. These obligations, if ultimately upheld by the courts, could materially restrict PG&E Corporation's ability to meet other obligations.

Adverse resolution of pending litigation could have a material adverse effect on PG&E Corporation's financial condition and results of operation.

PG&E Corporation has been named in lawsuits filed by the California Attorney General and the City and County of San Francisco, or CCSF, alleging unfair or fraudulent business acts or practices in violation of California Business and Professions Section 17200, or Section 17200, based on alleged violations of conditions established in the CPUC's holding company decisions caused by PG&E Corporation's alleged failure to provide adequate financial support to the Utility during the California energy crisis. The plaintiffs alleged that the transfer of money from the Utility to PG&E Corporation in the form of dividends and share repurchases violated Section 17200. These lawsuits have been consolidated and are pending in the San Francisco Superior Court, or Superior Court. The Attorney General and CCSF seek significant damages, penalties or equitable relief. On October 8, 2003, the U.S. District Court for the Northern District of California, or the District Court, held that the claims for damages were property of the Utility's bankruptcy estate, thus removing the damages claims from the lawsuits. The Attorney General and CCSF have appealed that decision to the U.S. Court of Appeals for the Ninth Circuit, or the Ninth Circuit, where it is currently pending. Oral argument on the appeal will be held on February 18, 2005. It is uncertain when a decision will be issued.

On January 21, 2005, the Superior Court issued a tentative ruling rejecting the standard advocated by the Attorney General and CCSF to calculate the number of violations that plaintiffs allege have been committed for purposes of determining the amount of potential civil penalties at issue. Under Section 17200, a penalty of up to \$2,500 can be imposed for each violation. The Superior Court found that the appropriate standard was each transfer of money from the Utility to PG&E Corporation that plaintiffs allege violated Section 17200. Comments on the ruling are scheduled to be discussed at a case management conference to be held on February 25, 2005. PG&E Corporation believes that the plaintiffs' allegations are without merit. However, there can be no assurance that PG&E Corporation will prevail in these lawsuits.

Risks Related to the Utility

If either or both of the CPUC's approval of the Settlement Agreement and the confirmation order are overturned or modified on appeal, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

On December 18, 2003, the CPUC approved the Settlement Agreement and, on December 22, 2003, the bankruptcy court confirmed the Utility's plan of reorganization, which fully incorporates the Settlement Agreement as a material and integral part of the plan. On March 16, 2004, the CPUC denied applications that had been filed by several parties seeking rehearing of the CPUC's decision approving the Settlement Agreement. On April 15, 2004, two of these parties, CCSF and Aglet

Consumer Alliance, or Aglet, filed petitions for review of the CPUC's decisions with the California Court of Appeal. Three California state senators have filed a brief in support of the CCSF and Aglet petitions. The California Court of Appeal has not yet acted on the petitions.

In addition, appeals of the confirmation order were filed in the District Court by the two CPUC commissioners who did not vote to approve the Settlement Agreement, or the dissenting commissioners, and a municipality. On July 15, 2004, the District Court dismissed the appeals filed by the dissenting commissioners. The dissenting commissioners have appealed the District Court's order with the Ninth Circuit. The municipality's appeal remains pending at the District Court.

If the bankruptcy court's confirmation of the Utility's plan of reorganization or the Settlement Agreement is overturned or modified on appeal, PG&E Corporation's and the Utility's financial condition and results of operations, and the Utility's ability to pay dividends or otherwise make distributions to PG&E Corporation, could be materially adversely affected.

PG&E Corporation's and the Utility's financial viability depends upon the Utility's ability to recover its costs in a timely manner from the Utility's customers through regulated rates and otherwise execute its business strategy.

The Utility is a regulated entity subject to CPUC jurisdiction in almost all aspects of its business, including the rates, terms and conditions of its services, procurement of electricity and natural gas for its customers, issuance of securities, dispositions of utility assets and facilities and aspects of the siting and operation of its electricity and natural gas distribution systems. Executing the Utility's business strategy depends on periodic CPUC approvals of these and related matters. The Utility's ongoing financial viability depends on its ability to recover from its customers in a timely manner the Utility's costs, including the costs of electricity and natural gas purchased by it for its customers, in the Utility's CPUC-approved rates and its ability to pass through to its customers in rates the Utility's FERC-authorized revenue requirements.

The Utility's financial viability also depends on its ability to recover in rates an adequate return on its capital structure, including long-term debt and equity. During the California energy crisis, the high price the Utility had to pay for electricity on the wholesale market, coupled with its inability to fully recover its costs in retail rates, caused the Utility's costs to significantly exceed its revenues and ultimately caused the Utility to file a petition under Chapter 11. Even though the Settlement Agreement and current regulatory mechanisms contemplate that the CPUC will give the Utility the opportunity to recover its reasonable and prudent future costs in its rates, there can be no assurance that the CPUC will find that all of the Utility's costs are reasonable and prudent or will not otherwise take or fail to take actions to the Utility's detriment.

In addition, there can be no assurance that the bankruptcy court or other courts will implement and enforce the terms of the Settlement Agreement and the Utility's plan of reorganization in a manner that would produce the economic results that PG&E Corporation and the Utility intend or anticipate. Further, there can be no assurance that FERC-authorized tariffs will be adequate to cover the related costs. If the Utility is unable to recover any material amount of its costs through its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

The Utility may be unable to purchase electricity in the wholesale market or to increase its generating capacity in a manner that the CPUC will find reasonable or in amounts sufficient to satisfy the Utility's obligation to meet the electricity needs of its customers and the CPUC's electricity resource adequacy requirements.

The Utility's residual net open position (*i.e.* , that portion of the Utility's electricity customers' demand not satisfied by electricity that the Utility generates or has under contract, or by electricity provided under the DWR allocated contracts) is expected to grow over time, as discussed in the "Risk

Management" section of this MD&A above. In addition, unexpected outages at the Utility's Diablo Canyon power plant or any of its other significant generation facilities, or a failure to perform by any of the counterparties to the Utility's electricity purchase contracts or the DWR allocated contracts, would immediately increase the Utility's residual net open position.

As existing electricity purchase contracts expire, sources of electricity otherwise become unavailable or demand increases, the Utility will purchase electricity in the wholesale market. These purchases will be made under contracts priced at the time of execution or, if made in the spot market, at the then-current market price of wholesale electricity. There can be no assurance that sufficient replacement electricity will be available at prices and on terms that the CPUC will find reasonable, or at all. The Utility's financial condition and results of operations would be materially adversely affected if it is unable to purchase electricity in the wholesale market at prices or on terms the CPUC finds reasonable or in quantities sufficient to satisfy the Utility's residual net open position.

California investor-owned electric utilities are required to achieve an electricity planning reserve margin of 15% to 17% in excess of peak capacity electricity requirements by June 1, 2006. In order to meet electricity resource adequacy requirements, the Utility may develop or acquire new generation facilities. The development or acquisition of additional generation facilities would require the Utility to incur significant additional capital expenditures or other costs and may require the Utility to issue additional debt, which it may not be able to issue on reasonable terms, or at all. The CPUC's December 16, 2004 decision approving the Utility's LTPP prohibits the Utility from recovering costs in excess of the Utility's projection of its initial capital costs included in the Utility's bid for Utility-owned generation. If the Utility is not able to recover a material part of the cost of developing or acquiring additional generation facilities in the Utility's rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

The Utility's financial condition and results of operations could be materially adversely affected if it is unable to successfully manage the risks inherent in operating the Utility's facilities.

The Utility owns and operates extensive electricity and natural gas facilities that are interconnected to the U.S. western electricity grid and numerous interstate and continental natural gas pipelines. The operation of the Utility's facilities and the facilities of third parties on which it relies involves numerous risks, including:

- Operating limitations that may be imposed by environmental or other regulatory requirements;
- Imposition of operational performance standards by agencies with regulatory oversight of the Utility's facilities;
- Environmental and personal injury liabilities;
- Fuel interruptions;
- Blackouts;
- Labor disputes;
- Weather, storms, earthquakes, fires, floods or other natural disasters; and
- Explosions, accidents, mechanical breakdowns and other events or hazards that affect demand, result in power outages, reduce generating output or cause damage to the Utility's assets or operations or those of third parties on which it relies.

The occurrence of any of these events could result in lower revenues or increased expenses, or both, that may not be fully recovered through insurance, rates or other means in a timely manner or at all.

Electricity and natural gas markets are highly volatile and insufficient regulatory responsiveness to that volatility could cause events similar to those that led to the filing of the Utility's Chapter 11 petition to occur.

In the recent past, the commodity markets for electricity and natural gas have been highly volatile and subject to substantial price fluctuations. A variety of factors may contribute to commodity market volatility, including:

- Weather;
- Supply and demand;
- The availability of competitively priced alternative energy sources;
- The level of production of natural gas;
- The availability of liquified natural gas, or LNG, supplies;
- The price of other fuels that are used to produce electricity, including crude oil and coal;
- The transparency, efficiency, integrity and liquidity of regional energy markets affecting California;
- Electricity transmission or natural gas transportation capacity constraints;
- Federal, state and local energy and environmental regulation and legislation; and
- Natural disasters, war, terrorism and other catastrophic events.

These factors are largely outside the Utility's control. If wholesale electricity or natural gas prices increase significantly, public pressure or other regulatory or governmental influences or other factors could constrain the willingness or ability of the CPUC to authorize timely recovery of the Utility's costs. Moreover, the volatility of commodity markets could cause the Utility to apply more frequently to the CPUC for authority to timely recover its costs in rates. If the Utility is unable to recover any material amount of its costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

The Utility's operations are subject to extensive environmental laws, and changes in, or liabilities under, these laws could adversely affect its financial condition and results of operations.

The Utility's operations are subject to extensive federal, state and local environmental laws. Complying with these environmental laws has in the past required significant expenditures for environmental compliance, monitoring and pollution control equipment, as well as for related fees and permits. Moreover, compliance in the future may require significant expenditures relating to electric and magnetic fields. The Utility also is subject to significant liabilities related to the investigation and remediation of environmental contamination at the Utility's current and former facilities, as well as at third-party owned sites. Due to the potential for imposition of stricter standards and greater regulation in the future and the possibility that other potentially responsible parties may not be financially able to contribute to cleanup costs, conditions may change or additional contamination may be discovered, the Utility's environmental compliance and remediation costs could increase, and the timing of its capital expenditures in the future may accelerate. If the Utility is unable to recover the costs of complying with environmental laws in its rates in a timely manner, the Utility's financial condition and results of operations could be materially adversely affected. In addition, in the event the Utility must pay materially more than the amount that it currently has reserved on its balance sheet to satisfy its environmental remediation obligations and the Utility is unable to recover these costs from insurance or through rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

The Utility faces the risk of unrecoverable costs if its customers obtain distribution and transportation services from other providers as a result of municipalization, competition, technological change, or other forms of bypass.

The Utility's customers could bypass its distribution and transportation system by obtaining service from other sources. Forms of bypass of the Utility's electricity distribution system include the construction of duplicate distribution facilities to serve specific existing or new customers, the municipalization of the Utility's distribution facilities by local governments or districts, and other forms of bypass or competition. Bypass of the Utility's system may result in stranded investment capital, loss of customer growth or additional barriers to cost recovery. Recently, both the Sacramento Municipal Utility District and South San Joaquin Irrigation District have studied the feasibility of condemning portions of the Utility's electric system within Yolo County and San Joaquin County, respectively. If these agencies continue their efforts, they must satisfy a number of legal steps, which will likely span several years. The Utility opposes these efforts as not being within the best interests of the customers within the subject areas, as well as other customers. The Utility's natural gas transportation facilities also are at risk of being bypassed by interstate pipeline companies that construct facilities in the Utility's markets or by customers who build pipeline connections that bypass the Utility's natural gas transportation and distribution system, or by customers who use and transport LNG. As customers and local public officials explore their energy options in light of the California energy crisis, these bypass risks may be increasing and may increase further if the Utility's rates exceed the cost of other available alternatives. In addition, technological changes could result in the development of economically attractive alternatives to purchasing electricity through the Utility's distribution facilities. Neither PG&E Corporation nor the Utility can currently predict the impact of these actions and developments on the Utility's business, although one possible outcome is a decline in the demand for the services that the Utility provides, which would result in a corresponding decline in the Utility's revenues and PG&E Corporation's consolidated revenues.

If the number of the Utility's customers declines due to municipalization, competition, technological changes or other forms of bypass, and the Utility's rates are not adjusted in a timely manner to allow it to fully recover its investment in electricity and natural gas facilities and electricity procurement costs, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

The Utility faces the risk of unrecoverable costs resulting from changes in the number of customers in its service territory for whom the Utility purchases electricity.

As part of California's electricity industry restructuring, the Utility's customers were given the ability to choose to purchase electricity from alternate energy service providers and to thus become direct access customers. Customers who did not buy electricity from an alternate provider continued to receive electricity procurement, transmission and distribution services, or bundled service, from the Utility. Customers who chose an alternate electricity provider continued to receive transmission and distribution services from the Utility. The CPUC suspended the right of end-user customers to become direct access customers on September 20, 2001, although customers that were then direct access customers have been allowed to remain on direct access. During the 2003-2004 legislative session, the California legislature considered bills, including California Assembly Bill 428, or AB 428, which would have required the CPUC to establish rules for reintroduction of direct access through a phased implementation and to establish a model for direct access transactions. AB 428 would also have required the CPUC, for the period January 1, 2006 through January 1, 2009, to permit new direct access transactions in an amount equivalent to the combined amount of Statewide utility load growth and reduction in the electricity supply contract obligations of the DWR. While AB 428 was not approved by the legislature, there can be no assurance that a similar bill will not be introduced and approved in future legislative sessions.

Separately, the CPUC has instituted a rulemaking implementing California's Assembly Bill 117, which permits California cities and counties to purchase and sell electricity for their residents once they have registered as community choice aggregators. The Utility would continue to provide distribution, metering and billing services to the community choice aggregators' customers. Once registration has occurred, and the applicable community choice aggregator has received CPUC approval for its implementation plan, the community choice aggregator would purchase electricity for all of its residents who do not affirmatively elect to continue to receive electricity from the Utility. The Utility would continue to be the electricity provider of last resort for all customers. If the Utility loses a material number of customers as a result of cities and counties electing to become community choice aggregators or the CPUC once again allows customers to migrate to direct access, the Utility's electricity purchase contracts could obligate it to purchase more electricity than the Utility's remaining customers require, the excess of which the Utility would have to sell, possibly at a loss. Further, if the Utility must provide electricity to customers discontinuing direct access or electing to leave a community choice aggregator, the Utility may be required to make unanticipated purchases of additional electricity at higher prices. If the Utility has excess electricity or it must make unplanned purchases of electricity as a result of changes in the number of community choice aggregators' customers or direct access customers and the CPUC fails to adjust the Utility's rates to reflect the impact of these actions, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures.

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures, including those arising from the storage, handling and disposal of radioactive materials and uncertainties related to the regulatory, technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives. The Utility maintains decommissioning trusts and external insurance coverage to reduce the Utility's financial exposure to these risks. However, the costs or damages the Utility may incur in connection with the operation and decommissioning of nuclear power plants could exceed the amount of the Utility's insurance coverage and other amounts set aside for these potential liabilities. In addition, as an operator of two operating nuclear reactor units, the Utility may be required under federal law to pay up to \$201.2 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon power plant but at any other nuclear power plant in the United States.

In January 2004, the Utility filed an application with the CPUC seeking approval of projects to replace turbines and steam generators and other equipment at the two nuclear operating units at the Utility's Diablo Canyon nuclear power plant and authorization to recover the projected \$706 million capital expenditures in rates. The Utility plans to replace Unit 2's steam generators in 2008 and to replace Unit 1's steam generators in 2009. On January 25, 2005, a CPUC administrative law judge issued a proposed decision that would find the steam generator replacement project to be cost-effective and would authorize the Utility to recover the projected \$706 million capital cost of the project in rates with no after-the-fact reasonableness review if the total costs do not exceed \$706 million, and established a maximum project cost of \$815 million. If the project costs exceed \$706 million, or if the CPUC has reason to believe that the costs may be unreasonable regardless of the amount, the CPUC may conduct a reasonableness review of all costs. The proposed decision recommends that the Utility would be allowed to recover the revenue requirements related to the project in rates beginning on January 1 of the year following the commencement of commercial operations of each unit. The CPUC may act on the proposed decision at its meeting to be held on February 25, 2005. Assuming the CPUC approves the proposed decision, the Utility would make the initial capital expenditures required to maintain a 2008/2009 implementation schedule. It is expected that the CPUC will issue a final decision, including incorporation of the environmental impact review for the projects, in September 2005. If the Utility cannot recover any material amount of these excess costs or damages in the Utility's rates in a

timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

In addition, the NRC has broad authority under federal law to impose licensing and safety-related requirements upon owners and operators of nuclear power plants. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of the nuclear plant, or both, depending upon the NRC's assessment of the severity of the situation. Safety and security requirements promulgated by the NRC have, in the past, necessitated substantial capital expenditures at the Utility's Diablo Canyon power plant and additional significant capital expenditures could be required in the future.

If the Utility fails to increase the spent fuel storage capacity at the Utility's Diablo Canyon power plant by the spring of 2007 and there are no other available spent fuel storage or disposal alternatives, the Utility would be forced to close this plant and would therefore be required to purchase electricity from more expensive sources.

Under the terms of the NRC operating licenses for the Utility's Diablo Canyon power plant, there must be sufficient storage capacity for the radioactive spent fuel produced by this plant. Under current operating procedures, the Utility believes that its Diablo Canyon power plant's existing spent fuel pools have sufficient capacity to enable it to operate until the spring of 2007. Although the Utility is taking actions to increase the Diablo Canyon power plant's spent fuel storage capacity and exploring other alternatives, there can be no assurance that the Utility can obtain the final necessary regulatory approvals to expand spent fuel capacity or that other alternatives will be available or implemented in time to avoid a disruption in production or shutdown of one or both units at this plant. As the proposed permanent spent fuel depository at Yucca Mountain, Nevada will not be available by 2007, there will not be any available third-party spent fuel storage facilities. If there is a disruption in production or shutdown of one or both units at this plant, the Utility will need to purchase electricity from more expensive sources.

Acts of terrorism could materially adversely affect PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility's facilities, including its operating and retired nuclear facilities and the facilities of third parties on which we rely, could be targets of terrorist activities. A terrorist attack on these facilities could result in a full or partial disruption of the Utility's ability to generate, transmit, transport or distribute electricity or natural gas or cause environmental repercussions. Any operational disruption or environmental repercussions could result in a significant decrease in the Utility's revenues or significant reconstruction or remediation costs, which could materially adversely affect PG&E Corporation's and the Utility's financial condition and results of operations.

Adverse judgments or settlements in the chromium litigation cases could materially adversely affect PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility is a named defendant in 14 civil actions currently pending in California courts relating to alleged chromium contamination. The chromium litigation complaints allege personal injuries, wrongful death and loss of consortium and seek unspecified compensatory and punitive damages based on claims arising from alleged exposure to chromium contamination in the vicinity of three of the Utility's natural gas compressor stations. If the Utility pays a material amount in excess of the amount that it currently has reserved on its balance sheet to satisfy chromium-related liabilities and costs, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

The Utility's operations are subject to a number of federal and state statutes, CPUC and FERC regulations, rules and orders, as well as the terms of governmental permits, authorizations and licenses.

The Utility is obligated to comply in good faith with all applicable statutes, rules, tariffs and orders of the CPUC, the FERC and the NRC relating to the aspects of its electricity and natural gas utility operations which fall within the jurisdictional authority of such regulatory agencies. These include customer billing, customer service, affiliate transactions, vegetation management, and safety and inspection practices. There is a risk that the interpretation and application of these statutes, rules, tariffs and orders may change over time and that the Utility will be determined to have not complied with the new interpretation exposing the Utility to potential liability for customer refunds, penalties, or other amounts. As an example, the Utility is required to reimburse the California Department of Forestry, or CDF, for fire suppression costs when a fire on wild lands is caused by the Utility's failure to maintain a specified clearance between vegetation and overhead lines. Recently, the CDF has demanded the Utility pay for fire suppression costs regardless of whether the Utility is determined to be at fault in identifying and removing hazard trees.

Changes in, or liabilities under, the Utility's permits, authorizations or licenses could adversely affect PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility is also required to comply with the terms of various permits, authorizations and licenses. These permits, authorizations and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In connection with a license renewal, the FERC may impose new license conditions that could, among other things, require increased expenditures or result in reduced electricity output and/or capacity at the facility.

If the CPUC, the FERC, the NRC, or other regulatory agency having jurisdiction, makes a finding that the Utility did not comply with applicable rules, tariffs and orders, the Utility could be required to make customer refunds, pay penalties, or incur other non-recoverable expenses, which could have a material adverse effect on PG&E Corporation's and the Utility's financial condition and results of operations. Also, if the Utility is unable to obtain, renew or comply with these governmental permits, authorizations or licenses, or the Utility is unable to recover any increased costs of complying with additional license requirements or any other associated costs in its rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations could be materially adversely affected.

PG&E Corporation

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share amounts)

	Year ended December 31,		
	2004	2003	2002
Operating Revenues			
Electric	\$ 7,867	\$ 7,582	\$ 8,178
Natural gas	3,213	2,853	2,327
Total operating revenues	11,080	10,435	10,505
Operating Expenses			
Cost of electricity	2,770	2,309	1,447
Cost of natural gas	1,724	1,438	895
Operating and maintenance	2,865	2,963	2,858
Recognition of regulatory assets	(4,900)	—	—
Depreciation, amortization, and decommissioning	1,497	1,222	1,196
Reorganization professional fees and expenses	6	160	155
Total operating expenses	3,962	8,092	6,551
Operating Income	7,118	2,343	3,954
Reorganization interest income	8	46	71
Interest income	55	16	9
Interest expense	(797)	(1,147)	(1,224)
Other income (expense), net	(98)	(9)	50
Income Before Income Taxes	6,286	1,249	2,860
Income tax provision	2,466	458	1,137
Income From Continuing Operations	3,820	791	1,723
Discontinued Operations			
Gain on disposal of NEGT (net of income taxes of \$374 million)	684	—	—
Loss from operations of NEGT (net of income tax benefit of \$230 million in 2003 and \$1,558 million in 2002)	—	(365)	(2,536)
Net Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	4,504	426	(813)
Cumulative effect of changes in accounting principles of \$(5) million in 2003 and \$(61) million in 2002 related to discontinued operations (net of income tax benefit of \$3 million in 2003 and \$42 million in 2002). In 2003, \$(1) million related to continuing operations (net of income tax benefit of \$1 million)	—	(6)	(61)
Net Income (Loss)	\$ 4,504	\$ 420	\$ (874)
Weighted Average Common Shares Outstanding, Basic	398	385	371
Earnings Per Common Share from Continuing Operations, Basic	\$ 9.16	\$ 1.96	\$ 4.53
Net Earnings (Loss) Per Common Share, Basic	\$ 10.80	\$ 1.04	\$ (2.30)
Earnings Per Common Share from Continuing Operations, Diluted	\$ 8.97	\$ 1.92	\$ 4.49
Net Earnings (Loss) Per Common Share, Diluted	\$ 10.57	\$ 1.02	\$ (2.27)

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2004	2003
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 972	\$ 3,658
Restricted cash	1,980	403
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$93 million in 2004 and \$68 million in 2003)	2,085	2,424
Related parties	—	15
Regulatory balancing accounts	1,021	248
Inventories:		
Gas stored underground	175	166
Materials and supplies	129	126
Prepaid expenses and other	46	108
Total current assets	6,408	7,148
Property, Plant and Equipment		
Electric	21,519	20,468
Gas	8,526	8,355
Construction work in progress	449	379
Other	15	20
Total property, plant and equipment	30,509	29,222
Accumulated depreciation	(11,520)	(11,115)
Net property, plant and equipment	18,989	18,107
Other Noncurrent Assets		
Regulatory assets	6,526	2,001
Nuclear decommissioning funds	1,629	1,478
Other	988	1,441
Total other noncurrent assets	9,143	4,920
TOTAL ASSETS	\$ 34,540	\$ 30,175

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation

CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)

	Balance at December 31,	
	2004	2003
LIABILITIES AND SHAREHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short-term borrowings	\$ 300	\$ —
Long-term debt, classified as current	758	310
Rate reduction bonds, classified as current	290	290
Accounts payable:		
Trade creditors	762	657
Disputed claims	2,142	—
Regulatory balancing accounts	369	186
Other	352	402
Interest payable	461	174
Income taxes payable	185	256
Deferred income taxes	394	102
Other	905	761
Total current liabilities	6,918	3,138
Noncurrent Liabilities		
Long-term debt	7,323	3,314
Rate reduction bonds	580	870
Regulatory liabilities	4,035	3,979
Asset retirement obligations	1,301	1,218
Deferred income taxes	3,531	856
Deferred tax credits	121	127
Net investment in NEGT	—	1,216
Preferred stock of subsidiary with mandatory redemption provisions (redeemable, 6.30% and 6.57%, outstanding 4,925,000 shares, due 2005-2009)	122	137
Other	1,690	1,501
Total noncurrent liabilities	18,703	13,218
Liabilities Subject to Compromise		
Financing debt	—	5,603
Trade creditors	—	3,715
Total liabilities subject to compromise	—	9,318
Commitments and Contingencies (Notes 1, 2, 5 and 12)		
Preferred Stock of Subsidiaries	286	286
Preferred Stock		
Preferred stock, no par value, 80,000,000 shares, \$100 par Value, 5,000,000 shares, none issued	—	—
Common Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 417,014,431 common and 1,601,710 restricted shares in 2004 and 414,985,014 common and 1,535,268 restricted shares in 2003	6,518	6,468
Common stock held by subsidiary, at cost, 24,665,500 shares in 2004 and 23,815,500 shares in 2003	(718)	(690)
Unearned compensation	(26)	(20)
Accumulated earnings (deficit)	2,863	(1,458)
Accumulated other comprehensive loss	(4)	(85)
Total common shareholders' equity	8,633	4,215
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 34,540	\$ 30,175

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year ended December 31,		
	2004	2003	2002
Cash Flows From Operating Activities			
Net income (loss)	\$ 4,504	\$ 420	\$ (874)
Gain on disposal of NEGТ (net of income taxes of \$374 million)	(684)	—	—
Loss from discontinued operations	—	365	2,536
Cumulative effect of changes in accounting principles	—	6	61
Net income from continuing operations	3,820	791	1,723
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, amortization and decommissioning	1,497	1,222	1,196
Recognition of regulatory assets	(4,900)	—	—
Deferred income taxes and tax credits, net	2,607	190	(281)
Reversal of ISO accrual	—	—	(970)
Other deferred charges and noncurrent liabilities	(519)	857	921
Loss from retirement of long-term debt	65	89	153
Tax benefit from employee stock plans	41	—	—
Gain on sale of assets	(19)	(29)	—
Net effect of changes in operating assets and liabilities:			
Restricted cash	494	(237)	(473)
Accounts receivable	(85)	(605)	212
Inventories	(12)	(17)	62
Accounts payable	273	403	198
Accrued taxes	(122)	173	(619)
Regulatory balancing accounts, net	(590)	(329)	(23)
Other working capital	712	(90)	22
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(1,022)	(87)	(1,442)
Other, net	110	171	135
Net cash provided by operating activities	2,350	2,502	814
Cash Flows From Investing Activities			
Capital expenditures	(1,559)	(1,698)	(1,547)
Net proceeds from sale of assets	35	49	11
Increase in restricted cash	(1,710)	—	—
Other, net	(178)	(112)	25
Net cash used in investing activities	(3,412)	(1,761)	(1,511)
Cash Flows From Financing Activities			
Net borrowings under credit facilities and short-term borrowings	300	—	—
Proceeds from issuance of long-term debt, net of issuance costs of \$107 million in 2004	7,742	581	847
Long-term debt matured, redeemed or repurchased	(9,054)	(1,068)	(1,241)
Rate reduction bonds matured	(290)	(290)	(290)
Preferred stock with mandatory redemption provisions redeemed	(15)	—	—
Common stock issued	162	166	217
Common stock repurchased	(378)	—	—
Preferred dividends paid	(90)	—	—
Other, net	(1)	(4)	—
Net cash used in financing activities	(1,624)	(615)	(467)
Net change in cash and cash equivalents	(2,686)	126	(1,164)
Cash and cash equivalents at January 1	3,658	3,532	4,696
Cash and cash equivalents at December 31	\$ 972	\$ 3,658	\$ 3,532

Supplemental disclosures of cash flow information

Cash received for:				
Reorganization interest income	\$	16	\$	39
			\$	75
Cash paid for:				
Interest (net of amounts capitalized)		646	866	1,414
Income taxes paid (refunded), net		128	(91)	971
Reorganization professional fees and expenses		61	99	99
Supplemental disclosures of noncash investing and financing activities				
Transfer of liabilities and other payables subject to compromise (to) from operating assets and liabilities	\$	(2,877)	\$	181
			\$	419

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(in millions, except share amounts)

	Common Stock		Common Stock Held by Subsidiary	Unearned Compensation	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholders' Equity	Comprehensive income (Loss)
	Shares	Amount						
Balance at December 31, 2001	387,898,848	\$ 5,986	\$ (690)	—	\$ (1,004)	\$ 30	\$ 4,322	
Net loss	—	—	—	—	(874)	—	(874)	\$ (874)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax benefit of \$44 million)	—	—	—	—	—	(139)	(139)	(139)
Net reclassification to earnings (net of income tax expense of \$4 million)	—	—	—	—	—	13	13	13
Foreign currency translation adjustment (net of income tax expense of \$1 million)	—	—	—	—	—	2	2	2
Other (net of zero income tax)	—	—	—	—	—	1	1	1
Comprehensive loss								\$ (997)
Common stock issued	17,582,636	217	—	—	—	—	217	
Common stock repurchased	(6,580)	—	—	—	—	—	—	
Warrants issued	—	71	—	—	—	—	71	
Common stock warrants exercised	11,111	—	—	—	—	—	—	
Balance at December 31, 2002	405,486,015	6,274	(690)	—	(1,878)	(93)	3,613	
Net income	—	—	—	—	420	—	420	\$ 420
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax benefit of \$10 million)	—	—	—	—	—	(8)	(8)	(8)
Retirement plan remeasurement (net of income tax benefit of \$3 million)	—	—	—	—	—	(4)	(4)	(4)
Net reclassification to earnings (net of income tax expense of \$27 million)	—	—	—	—	—	17	17	17
Foreign currency translation adjustment (net of income tax expense of \$5 million)	—	—	—	—	—	3	3	3
Comprehensive income								\$ 428
Common stock issued	8,796,632	166	—	—	—	—	166	
Common stock warrants exercised	702,367	—	—	—	—	—	—	
Common restricted stock issued	1,590,010	28	—	(28)	—	—	—	
Common restricted stock cancelled	(54,742)	(1)	—	1	—	—	—	
Common restricted stock amortization	—	—	—	7	—	—	7	
Other	—	1	—	—	—	—	1	
Balance at December 31, 2003	416,520,282	6,468	(690)	(20)	(1,458)	(85)	4,215	
Net income	—	—	—	—	4,504	—	4,504	\$ 4,504
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax expense of \$2 million)	—	—	—	—	—	3	3	3
NEGT losses reclassified to earnings upon elimination of equity interest by PG&E Corporation (net of income tax expense of \$43 million)	—	—	—	—	—	77	77	77
Other	—	—	—	—	—	1	1	1
Comprehensive income								\$ 4,585
Common stock issued	8,410,058	162	—	—	—	—	162	
Common stock repurchased	(10,783,200)	(167)	—	—	(183)	—	(350)	
Common stock held by subsidiary	—	—	(28)	—	—	—	(28)	
Common stock warrants exercised	4,003,812	—	—	—	—	—	—	
Common restricted stock issued	498,910	16	—	(16)	—	—	—	
Common restricted stock cancelled	(33,721)	(1)	—	1	—	—	—	
Common restricted stock amortization	—	—	—	9	—	—	9	
Tax benefit from employee stock plans	—	41	—	—	—	—	41	

Other	—	(1)	—	—	—	—	(1)
Balance at December 31, 2004	418,616,141	\$ 6,518	\$ (718)	\$ (26)	\$ 2,863	\$ (4)	\$ 8,633

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions)

	Year ended December 31,		
	2004	2003	2002
Operating Revenues			
Electric	\$ 7,867	\$ 7,582	\$ 8,178
Natural gas	3,213	2,856	2,336
Total operating revenues	11,080	10,438	10,514
Operating Expenses			
Cost of electricity	2,770	2,319	1,482
Cost of natural gas	1,724	1,467	954
Operating and maintenance	2,842	2,935	2,817
Recognition of regulatory assets	(4,900)	—	—
Depreciation, amortization and decommissioning	1,494	1,218	1,193
Reorganization professional fees and expenses	6	160	155
Total operating expenses	3,936	8,099	6,601
Operating Income	7,144	2,339	3,913
Reorganization interest income	8	46	71
Interest income	42	7	3
Interest expense (non-contractual interest expense of \$31 million in 2004, \$131 million in 2003, and \$149 million in 2002)	(667)	(953)	(988)
Other income (expense), net	16	13	(2)
Income Before Income Taxes	6,543	1,452	2,997
Income tax provision	2,561	528	1,178
Net Income Before Cumulative Effect of a Change in Accounting Principle	3,982	924	1,819
Cumulative effect of a change in accounting principle (net of income tax benefit of \$1 million in 2003)	—	(1)	—
Net Income	3,982	923	1,819
Preferred dividend requirement	21	22	25
Income Available for Common Stock	\$ 3,961	\$ 901	\$ 1,794

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance at December 31,	
	2004	2003
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 783	\$ 2,979
Restricted cash	1,980	403
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$93 million in 2004 and \$68 million in 2003)	2,085	2,424
Related parties	2	17
Regulatory balancing accounts	1,021	248
Inventories:		
Gas stored underground and fuel oil	175	166
Materials and supplies	129	126
Prepaid expenses and other	43	100
Total current assets	6,218	6,463
Property, Plant and Equipment		
Electric	21,519	20,468
Gas	8,526	8,355
Construction work in progress	449	379
Total property, plant and equipment	30,494	29,202
Accumulated depreciation	(11,507)	(11,100)
Net property, plant and equipment	18,987	18,102
Other Noncurrent Assets		
Regulatory assets	6,526	2,001
Nuclear decommissioning funds	1,629	1,478
Other	942	1,022
Total other noncurrent assets	9,097	4,501
TOTAL ASSETS	\$ 34,302	\$ 29,066

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company
CONSOLIDATED BALANCE SHEETS
(in millions, except share amounts)

	Balance at December 31,	
	2004	2003
LIABILITIES AND SHAREHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Short term borrowings	\$ 300	\$ —
Long-term debt, classified as current	757	310
Rate reduction bonds, classified as current	290	290
Accounts payable:		
Trade creditors	762	657
Disputed claims	2,142	—
Related parties	20	224
Regulatory balancing accounts	369	186
Other	337	365
Interest payable	461	153
Income taxes payable	102	—
Deferred income taxes	377	86
Other	869	637
Total current liabilities	6,786	2,908
Noncurrent Liabilities		
Long-term debt	7,043	2,431
Rate reduction bonds	580	870
Regulatory liabilities	4,035	3,979
Asset retirement obligations	1,301	1,218
Deferred income taxes	3,629	1,334
Deferred tax credits	121	127
Preferred stock with mandatory redemption provisions (redeemable, 6.30% and 6.57%, outstanding 4,925,000 shares due 2005-2009)	122	137
Other	1,555	1,471
Total noncurrent liabilities	18,386	11,567
Liabilities Subject to Compromise		
Financing debt	—	5,603
Trade creditors	—	3,899
Total liabilities subject to compromise	—	9,502
Commitments and Contingencies (Notes 1, 2 and 12)		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	149
Common stock, \$5 par value, authorized 800,000,000 shares, issued 321,314,760 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	2,041	1,964
Reinvested earnings	5,667	1,706
Accumulated other comprehensive loss	(3)	(6)
Total shareholders' equity	9,130	5,089
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 34,302	\$ 29,066

See accompanying Notes to the Consolidated Financial Statements.



Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)

	Year ended December 31,		
	2004	2003	2002
Cash Flows From Operating Activities			
Net income	\$ 3,982	\$ 923	\$ 1,819
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and decommissioning	1,494	1,218	1,193
Recognition of regulatory assets	(4,900)	—	—
Deferred income taxes and tax credits, net	2,580	(75)	378
Reversal of ISO accrual	—	—	(970)
Other deferred charges and noncurrent liabilities	(391)	581	102
Gain on sale of assets	(19)	(29)	—
Cumulative effect of a change in accounting principle	—	1	—
Net effect of changes in operating assets and liabilities:			
Restricted cash	133	(253)	(97)
Accounts receivable	(85)	(590)	212
Inventories	(12)	(17)	62
Accounts payable	273	507	198
Accrued taxes	52	48	(345)
Regulatory balancing accounts, net	(590)	(329)	(23)
Other working capital	450	29	11
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(1,022)	(87)	(1,442)
Other, net	26	43	36
Net cash provided by operating activities	1,971	1,970	1,134
Cash Flows From Investing Activities			
Capital expenditures	(1,559)	(1,698)	(1,546)
Net proceeds from sale of assets	35	49	11
Increase in restricted cash	(1,710)	—	—
Other, net	(178)	(114)	26
Net cash used in investing activities	(3,412)	(1,763)	(1,509)
Cash Flows From Financing Activities			
Net borrowings under credit facilities and short-term borrowings	300	—	—
Proceeds from issuance of long-term debt, net of issuance costs of \$107 million in 2004	7,742	—	—
Long-term debt matured, redeemed or repurchased	(8,402)	(281)	(333)
Rate reduction bonds matured	(290)	(290)	(290)
Preferred dividends paid	(90)	—	—
Preferred stock with mandatory redemption provisions redeemed	(15)	—	—
Net cash used in financing activities	(755)	(571)	(623)
Net change in cash and cash equivalents	(2,196)	(364)	(998)
Cash and cash equivalents at January 1	2,979	3,343	4,341
Cash and cash equivalents at December 31	\$ 783	\$ 2,979	\$ 3,343
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	\$ 16	\$ 39	\$ 75
Cash paid for:			
Interest (net of amounts capitalized)	512	773	1,105
Income taxes paid, net	109	648	1,186
Reorganization professional fees and expenses	61	99	99
Supplemental disclosures of noncash investing and financing activities			

Transfer of liabilities and other payables subject to compromise (to) from operating assets and liabilities	\$	(2,877)	\$	181	\$	419
Equity contribution for settlement of POR payable		(129)		—		—

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(in millions, except share amounts)

	Preferred Stock Without Mandatory Redemption Provisions	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Total Shareholders' Equity	Comprehensive Income
Balance at December 31, 2001	\$ 294	\$ 1,606	\$ 1,964	\$ (475)	\$ (989)	\$ (2)	2,398	
Net Income	—	—	—	—	1,819	—	1,819	\$ 1,819
Foreign currency translation adjustments (net of income tax expense of \$1 million)	—	—	—	—	—	2	2	2
Comprehensive income								\$ 1,821
Preferred stock dividend	—	—	—	—	(25)	—	(25)	
Balance at December 31, 2002	294	1,606	1,964	(475)	805	—	4,194	
Net Income	—	—	—	—	923	—	923	\$ 923
Retirement plan remeasurement (net of income tax benefit of \$2 million)	—	—	—	—	—	(3)	(3)	(3)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax benefit of \$2 million)	—	—	—	—	—	(3)	(3)	(3)
Comprehensive income								\$ 917
Preferred stock dividend	—	—	—	—	(22)	—	(22)	
Balance at December 31, 2003	294	1,606	1,964	(475)	1,706	(6)	5,089	
Net Income	—	—	—	—	3,982	—	3,982	\$ 3,982
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax expense of \$2 million)	—	—	—	—	—	3	3	3
Comprehensive income								\$ 3,985
Equity contribution for settlement of POR payable (net of income taxes of \$52 million)	—	—	77	—	—	—	77	
Preferred stock dividend	—	—	—	—	(21)	—	(21)	
Balance at December 31, 2004	\$ 294	\$ 1,606	\$ 2,041	\$ (475)	\$ 5,667	\$ (3)	9,130	

See accompanying Notes to the Consolidated Financial Statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: GENERAL

Organization and Basis of Presentation

PG&E Corporation, incorporated in California in 1995, is an energy-based holding company that conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages primarily in the businesses of electricity and natural gas distribution, electricity generation, procurement and transmission, and natural gas procurement, transportation and storage. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. The Utility, incorporated in California in 1905, is the predecessor of PG&E Corporation.

As discussed further in Note 2, on April 12, 2004, the Utility's plan of reorganization under the provisions of Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, became effective, at which time the Utility emerged from Chapter 11.

Prior to October 29, 2004, the effective date of the plan of reorganization of National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, Inc., was the other significant subsidiary of PG&E Corporation. NEGT was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. On July 8, 2003, NEGT filed a voluntary petition for relief under Chapter 11. For the reasons described below in Note 5, PG&E Corporation considered NEGT to be an abandoned asset under Statement of Financial Accounting Standards, or SFAS, "Accounting for Impairment or Disposal of Long-Lived Assets," or SFAS No. 144, and, as a result, the operations of NEGT prior to July 8, 2003 and for all prior periods, are reflected as discontinued operations in the Consolidated Financial Statements. In addition, as discussed in Note 5, effective July 8, 2003, PG&E Corporation no longer consolidated the earnings and losses of NEGT or its subsidiaries and began accounting for its ownership interest in NEGT using the cost method, under which PG&E Corporation's investment in NEGT is reflected as a single amount within the December 31, 2003 Consolidated Balance Sheet of PG&E Corporation. On October 29, 2004, NEGT's plan of reorganization became effective and NEGT emerged from Chapter 11, at which time PG&E Corporation's equity interest in NEGT was cancelled.

This is a combined annual report of PG&E Corporation and the Utility. Therefore, the Notes to the Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Consolidated Financial Statements include its accounts and those of its wholly owned and controlled subsidiaries and variable interest entities for which it is subject to a majority of the risk of loss or gain. All intercompany transactions have been eliminated from the Consolidated Financial Statements.

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America, or GAAP, requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of revenues, expenses, assets and liabilities and the disclosure of contingencies and include, but are not limited to, estimates and assumptions used in determining the Utility's regulatory asset and liability balances based on probability assessments of regulatory recovery, revenues earned but not yet billed (including delayed billings), disputed claims, asset retirement obligations, allowance for doubtful accounts receivable, provisions for losses that are deemed probable from environmental remediation liabilities, pension liabilities, mark-to-market accounting under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, or SFAS No. 133, income tax related liabilities, litigation, and the Utility's review for impairment of long-lived assets and certain identifiable intangibles to be held and used whenever events or changes in circumstances indicate that the carrying amount of its assets might not

be recoverable. As these estimates and assumptions involve judgments on a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict, actual results could differ from these estimates. PG&E Corporation's and the Utility's Consolidated Financial Statements reflect all adjustments that management believes are necessary for the fair presentation of their financial position and results of operations for the periods presented.

During the Utility's Chapter 11 proceeding, PG&E Corporation's and the Utility's Consolidated Financial Statements are presented in accordance with the American Institute of Certified Public Accountants' Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code," or SOP 90-7. Under SOP 90-7, certain claims against the Utility existing before the Utility filed its Chapter 11 petition were classified as liabilities subject to compromise on PG&E Corporation's and the Utility's Consolidated Balance Sheets. Additionally, professional fees and expenses directly related to the Utility's Chapter 11 proceeding and interest income on funds accumulated during the Chapter 11 proceedings were reported separately as reorganization items.

The Utility discontinued the application of SOP 90-7 upon its emergence from Chapter 11 on April 12, 2004. The Consolidated Financial Statements as of and for the years ending December 31, 2003 and 2002, have been presented in accordance with SOP 90-7. Although the Utility emerged from Chapter 11 on April 12, 2004, the bankruptcy court retained jurisdiction, among other things, to resolve disputed claims made in the Chapter 11 case. Upon the effective date of the Utility's plan of reorganization, \$1.8 billion was deposited into escrow, pending the resolution of disputed claims, and has been classified as restricted cash in current assets on PG&E Corporation's and the Utility's December 31, 2004 Consolidated Balance Sheets. The related remaining pre-petition disputed claims are subject to resolution by the bankruptcy court and are classified as current liabilities on the Consolidated Balance Sheets at December 31, 2004.

Reclassifications

Certain amounts in the 2003 and 2002 Consolidated Financial Statements and Notes to the Consolidated Financial Statements have been reclassified to conform to the 2004 presentation. These reclassifications did not affect the consolidated net income of PG&E Corporation and the Utility for the periods presented, nor did they impact revenues, operating income, current assets or liabilities, or total assets or equity.

Earnings (Loss) Per Share

Earnings (loss) per share is calculated utilizing the "two-class" method by dividing earnings (loss) allocated to common shareholders by the weighted average number of common shares outstanding during the period.

The following is a reconciliation of PG&E Corporation's net income (loss) and weighted average common shares outstanding for calculating basic and diluted net income (loss) per share:

	Year ended December 31,		
	2004	2003	2002
	(in millions, except per share amounts)		
Income from continuing operations	\$ 3,820	\$ 791	\$ 1,723
Discontinued operations	684	(365)	(2,536)
Net income (loss) before cumulative effect of changes in accounting principles	4,504	426	(813)
Cumulative effect of changes in accounting principles	—	(6)	(61)
Net income (loss) for basic and diluted calculations	4,504	420	(874)
Weighted average common shares outstanding, basic	398	385	371
9.50% Convertible Subordinated Notes	19	19	9
Weighted average common shares outstanding and participating securities, basic	417	404	380
Weighted average common shares outstanding, basic	398	385	371
Employee Stock Options, Restricted Stock and PG&E Corporation shares held by grantor trusts and accelerated share repurchase agreement ⁽¹⁾	7	4	2
PG&E Corporation Warrants	2	5	2
Weighted average common shares outstanding, diluted	407	394	375
9.50% Convertible Subordinated Notes	19	19	9
Weighted average common shares outstanding and participating securities, diluted	426	413	384
Earnings (Loss) Per Common Share, Basic			
Income from continuing operations	\$ 9.16	\$ 1.96	\$ 4.53
Discontinued operations	1.64	(0.90)	(6.67)
Cumulative effect of changes in accounting principles	—	(0.01)	(0.16)
Rounding	—	(0.01)	—
Net earnings (loss) per common share, basic	\$ 10.80	\$ 1.04	\$ (2.30)
Earnings (Loss) Per Common Share, Diluted			
Income from continuing operations	\$ 8.97	\$ 1.92	\$ 4.49
Discontinued operations	1.60	(0.88)	(6.60)
Cumulative effect of changes in accounting principles	—	(0.01)	(0.16)
Rounding	—	(0.01)	—
Net earnings (loss) per common share, diluted	\$ 10.57	\$ 1.02	\$ (2.27)

⁽¹⁾ Includes approximately 222,000 shares of PG&E Corporation common stock potentially issuable in settlement of an obligation of PG&E Corporation of approximately \$7.4 million under an accelerated share repurchase agreement at December 31, 2004. See Note 6 for further discussion.

On March 31, 2004, the Financial Accounting Standards Board, or FASB, ratified the consensus reached by the Emerging Issues Task Force, or the EITF, on EITF Issue 03-06, "Participating Securities and the Two-Class Method under FASB Statement No. 128," or EITF 03-06. EITF 03-06 provides additional guidance related to the calculation of earnings per share under SFAS No. 128, "Earnings per Share," or SFAS No. 128, which includes application of the "two-class" method in computing earnings

per share, identification of participating securities, and requirements for the allocation of undistributed earnings (and losses) to participating securities.

PG&E Corporation currently has outstanding \$280 million of 9.50% Convertible Subordinated Notes due 2010, or Convertible Subordinated Notes, that are entitled to receive (non-cumulative) dividend payments without exercising the conversion option. These Convertible Subordinated Notes meet the criteria of a participating security in the calculation of basic earnings per share using the "two-class" method of SFAS No. 128. Therefore, EITF 03-06 requires that earnings be allocated between common stock and the participating security. PG&E Corporation adopted EITF 03-06 in the first quarter of 2004 and for all subsequent and all prior periods presented.

In applying the "two-class" method, the following reflects the earnings (loss) allocated to common shareholders after the inclusion of participation rights related to PG&E Corporation's Convertible Subordinated Notes in the allocation of earnings. The Convertible Subordinated Notes are convertible at the option of the holders into 18,558,655 common shares. All PG&E Corporation's participating securities participate on a 1:1 basis in dividends with common shareholders.

	2004	2003	2002
Earnings (loss) allocated to common shareholders, basic			
Income from continuing operations	\$ 3,646	\$ 754	\$ 1,682
Discontinued operations	653	(348)	(2,476)
Cumulative effect of changes in accounting principles	—	(6)	(60)
Rounding	—	—	1
	<u>\$ 4,299</u>	<u>\$ 400</u>	<u>\$ (853)</u>
Earnings (loss) allocated to common shareholders, diluted			
Income from continuing operations	\$ 3,650	\$ 755	\$ 1,683
Discontinued operations	653	(348)	(2,476)
Cumulative effect of changes in accounting principles	—	(6)	(60)
	<u>\$ 4,303</u>	<u>\$ 401</u>	<u>\$ (853)</u>

Options to purchase PG&E Corporation common shares of 7,046,710 in 2004, 16,008,087 in 2003 and 21,150,557 in 2002 were outstanding, but not included in the computation of diluted earnings per share because the option exercise prices were greater than the average market price.

PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted earnings per share.

Adoption of New Accounting Policies and Summary of Significant Accounting Policies

The accounting policies used by PG&E Corporation and the Utility include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the California Public Utilities Commission, or the CPUC, or the Federal Energy Regulatory Commission, or the FERC.

Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003

In May 2004, FASB issued Staff Position SFAS No. 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," or FSP 106-2. FSP 106-2 supersedes FSP 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," and provides guidance on the accounting, disclosure, effective date, and transition requirements related to the Medicare Prescription Drug Act. FSP 106-2 was effective for the third quarter of 2004. The

adoption of FSP 106-2 did not have any impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

The U.S. Department of Health and Human Services issued the final regulations on prescription drug benefits on January 21, 2005. Despite the initial preliminary conclusion that the Utility's postretirement medical plan, or the Plan, did not qualify for the federal subsidy, the final regulations may allow the Plan to qualify for the federal subsidy. PG&E Corporation and the Utility are continuing to evaluate the effects, if any, of the final regulations on the Plan, and the impact on the Consolidated Financial Statements.

Consolidation of Variable Interest Entities

In December 2003, FASB issued Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities," or FIN 46R. FIN 46R provides that an entity is a variable interest entity, or VIE, if it does not have sufficient equity investment at risk, or if the holders of the entity's equity instruments lack the essential characteristics of a controlling financial interest. FIN 46R requires that the company that is subject to a majority of the risk of loss from a VIE's activities, or is entitled to receive a majority of the entity's residual returns, or both, consolidate the VIE. A company that consolidates a VIE is called the primary beneficiary.

PG&E Corporation and the Utility adopted FIN 46R on January 1, 2004. The adoption of FIN 46R did not have any impact on net income.

Low-Income Housing Partnerships

The Utility invests in low-income housing partnerships, or LIHPs. The entities were formed to invest in low-income housing projects sponsored by non-profit organizations in the state of California. The Utility determined that it was the primary beneficiary of one LIHP, resulting in its consolidation, and an increase in total assets and total liabilities of \$12 million in PG&E Corporation's and the Utility's Consolidated Balance Sheets. The consolidated LIHP has issued debt in the amount of \$5 million, which is secured by assets of the partnership, totaling \$26 million, and the Utility's commitment to make capital infusions of approximately \$11 million over the next five years.

The Utility is not considered to be the primary beneficiary of any other LIHPs. The maximum exposure to loss from its investment in unconsolidated LIHPs is the Utility's investment of \$5 million at December 31, 2004.

Power Purchase Agreements

The nature of power purchase agreements is such that the Utility could have a significant variable interest in a power purchase agreement counterparty if that entity is a VIE owning one plant that sells substantially all of its output to the Utility, and the contract price for power is correlated with the plant's variable costs of production. The Utility determined that none of its current power purchase agreements represent significant variable interests. The EITF continues to review how companies determine whether an arrangement is a variable interest. Their findings could impact how the determination is applied to the Utility's power purchase agreements in the future.

Changes in Accounting for Certain Derivative Contracts

In November 2003, the FASB approved an amendment to an interpretation issued by the Derivatives Implementation Group, C15, or DIG C15, as previously amended in October 2001 and December 2001, that changed the definition of normal purchases and sales for certain power contracts that contain option-like features.

PG&E Corporation and the Utility had previously adopted the new DIG C15 guidelines prospectively for new derivative instruments entered into after June 30, 2003. On January 1, 2004, PG&E Corporation and the Utility adopted the new DIG C15 guidelines for certain power contracts that contain option-like features that existed prior to July 1, 2003. The adoption of DIG C15 did not have any impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

Regulation and Statement of Financial Accounting Standards No. 71

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with "Accounting for the Effects of Certain Types of Regulation," as amended, or SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. The Utility is regulated by the CPUC, the FERC and the Nuclear Regulatory Commission, or the NRC, among others. As discussed further in Note 2, during the first quarter of 2004, the Utility began reapplying SFAS No. 71 to its generation operations. As a result, as of March 31, 2004, the Utility recorded a generation regulatory asset of approximately \$1.2 billion. SFAS No. 71 now applies to all of the Utility's operations except for the operations of a natural gas pipeline.

SFAS No. 71 provides for recording regulatory assets and liabilities when certain conditions are met. Regulatory assets represent the capitalization of incurred costs that would otherwise be charged to expense when it is probable that the incurred costs will be included for ratemaking purposes in the future. Regulatory liabilities represent rate actions of a regulator that will result in amounts that are to be credited to customers through the ratemaking process.

To the extent that portions of the Utility's operations cease to be subject to SFAS No. 71 or recovery is no longer probable as a result of changes in regulation or the Utility's competitive position, the related regulatory assets and liabilities are written off.

Accounting for Financial Instruments with Characteristics of Both Liabilities and Equity

In May 2003, the FASB issued Statement No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity," or SFAS No. 150. SFAS No. 150 addresses concerns of how to measure and classify in the balance sheet certain financial instruments that have characteristics of both liabilities and equity. The following freestanding financial instruments must be classified as liabilities: mandatorily redeemable financial instruments, obligations to repurchase an issuer's equity shares by transferring assets, and certain obligations to issue a variable number of shares.

PG&E Corporation and the Utility adopted the requirements of SFAS No. 150 in the third quarter of 2003. As a result, the Utility reclassified approximately \$137 million of preferred stock with mandatory redemption provisions as a noncurrent liability. The reclassification did not have an impact on earnings of PG&E Corporation or the Utility. Upon adopting SFAS No. 150, all amounts paid or to be paid to the holders of preferred stock with mandatory redemption provisions in excess of the initial measured amount are reflected in interest expense. Dividends paid or accrued in prior periods have not been reclassified.

Accounting for Asset Retirement Obligations

On January 1, 2003, PG&E Corporation and the Utility adopted SFAS No. 143, "Accounting for Asset Retirement Obligations," or SFAS No. 143. The Utility identified its nuclear generation and certain fossil fuel generation facilities as having asset retirement obligations under SFAS No. 143. SFAS No. 143 requires that an asset retirement obligation be recorded at fair value in the period in which it is incurred if a reasonable estimate of fair value can be made. In the same period, the associated asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. In each subsequent period, the liability is accreted to its present value and the capitalized cost is depreciated over the useful life of the long-lived asset. Rate-regulated entities may recognize regulatory assets or

liabilities as a result of timing differences between the recognition of costs as recorded in accordance with SFAS No. 143 and costs recovered through the ratemaking process. The cumulative effect of the change in accounting principle for the Utility's fossil fuel facilities as a result of adopting SFAS No. 143 was a loss of approximately \$1 million, after-tax.

The Utility has established trust funds that are legally restricted for purposes of settling its nuclear decommissioning obligations. The fair value and carrying value of these trust funds was approximately \$1.6 billion at December 31, 2004 and approximately \$1.5 billion at December 31, 2003.

The Utility may have potential asset retirement obligations under various land right documents associated with its transmission and distribution facilities. The majority of the Utility's land rights are perpetual. Any non-perpetual land rights generally are renewed continuously because the Utility intends to utilize these facilities indefinitely. Since the timing and extent of any potential asset retirements are unknown, the fair value of any obligations associated with these facilities cannot be reasonably estimated.

The Utility collects estimated removal costs in rates through depreciation in accordance with regulatory treatment. These amounts do not represent SFAS No. 143 asset retirement obligations. Historically, these removal costs have been recorded in accumulated depreciation. However, as a result of guidance from the staff of the Securities and Exchange Commission, or SEC, the Utility reclassified this obligation to a regulatory liability in its 2003 and 2002 Consolidated Balance Sheet during 2003. The Utility's estimated removal costs recorded as a regulatory liability were approximately \$2.0 billion at December 31, 2004 and approximately \$1.8 billion at December 31, 2003.

Accounting for Goodwill and Other Intangible Assets

PG&E Corporation and the Utility had no goodwill on their Consolidated Balance Sheets at December 31, 2004 or 2003. Other intangible assets consist mainly of hydroelectric facility licenses and other agreements, with lives ranging from 17 to 40 years. The gross carrying amount of the hydroelectric facility licenses and other agreements was approximately \$73 million at December 31, 2004 and December 31, 2003. The accumulated amortization was approximately \$23 million at December 31, 2004 and \$19 million at December 31, 2003.

The Utility's amortization expense related to intangible assets was approximately \$4 million in 2004, \$3 million in 2003 and \$3 million in 2002. The estimated annual amortization expense based on the December 31, 2004 intangible asset balance for the Utility's intangible assets for 2005 through 2009 is approximately \$4 million each year.

Cash and Cash Equivalents

Invested cash and other investments with original maturities of three months or less are considered cash equivalents. Cash equivalents are stated at cost, which approximates fair value. PG&E Corporation and the Utility primarily invest their cash in money market funds and in short-term obligations of the U.S. government and its agencies.

The Utility had account balances with Citigroup Asset Management and Janus Capital Group that were greater than 10% of PG&E Corporation's and the Utility's total cash and cash equivalents balance at December 31, 2004.

Restricted Cash

Restricted cash includes Utility amounts held in escrow as required by the bankruptcy court related to remaining disputed claims and as collateral while in Chapter 11, as required by the California Independent System Operator, or ISO, the State of California and other counterparties. The Utility

also provides deposits to counterparties in the normal course of operations and under certain third party agreements.

Inventories

Inventories include materials, supplies and gas stored underground and are valued at average cost. Materials and supplies are charged to inventory when purchased and then expensed or capitalized to plant, as appropriate, when installed. Materials provisions are made for obsolete inventory. Gas stored underground is charged to inventory when purchased and then expensed upon distribution.

Income Taxes

PG&E Corporation and the Utility use the liability method of accounting for income taxes. Income tax expense (benefit) includes current and deferred income taxes resulting from operations during the year. Investment tax credits are amortized over the life of the related property. Other tax credits, mainly synthetic fuel tax credits, are recognized in income as earned.

PG&E Corporation files a consolidated U.S. (federal) income tax return that includes domestic subsidiaries in which its ownership is 80% or more. In addition, PG&E Corporation files combined state income tax returns where applicable. PG&E Corporation and the Utility are parties to a tax-sharing arrangement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

Prior to July 8, 2003, the date of NEGT's Chapter 11 filing, PG&E Corporation recognized federal income tax benefits related to the losses of NEGT and its subsidiaries. However, after July 7, 2003, under the cost method of accounting PG&E Corporation has not recognized additional income tax benefits for financial reporting purposes with respect to the losses of NEGT and its subsidiaries. PG&E Corporation is required to continue to include NEGT and its subsidiaries in its consolidated income tax returns covering all periods through October 29, 2004, the effective date of NEGT's plan of reorganization and the cancellation of its equity ownership in NEGT. See Note 11 for further discussion.

Investments in Affiliates

The Utility has investments in unconsolidated affiliates, which are mainly engaged in the purchase of low-income residential real estate property. The equity method of accounting is applied to the Utility's investment in these entities. Under the equity method, the Utility's share of equity income or losses of these entities is reflected as equity in earnings of affiliates. As of December 31, 2004, the Utility's recorded investment in these entities totaled approximately \$5 million in accordance with the equity method of accounting. As a limited partner, the Utility's exposure to potential loss is limited to its investment in each partnership.

Related Party Agreements and Transactions

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. These services are priced either at the fully loaded cost (*i.e.* , direct costs and allocations of overhead costs) or at the higher of fully loaded cost or fair market value, depending on the nature of the services. PG&E Corporation also allocates certain other corporate administrative and general costs to the Utility and other subsidiaries using agreed allocation factors, including the number of employees, operating expenses excluding fuel purchases, total assets and other cost allocation methodologies. The Utility purchases natural gas transportation services from Gas Transmission Northwest Corporation, or GTNW, formerly known as PG&E Gas Transmission, Northwest Corporation. Effective April 1, 2003, the Utility

no longer purchases natural gas from NEGT Energy Trading Holdings Corporation, or NEGT ET, formerly known as PG&E Energy Trading Holdings Corporation. Both GTNW and NEGT ET are no longer related parties after the cancellation of PG&E Corporation's equity interest in NEGT on the effective date of its plan of reorganization, October 29, 2004. The Utility sold natural gas transportation capacity and other ancillary services to NEGT ET until NEGT's Chapter 11 proceeding was imminent. These services were priced at either tariff rates or fair market value, depending on the nature of the services provided. Through July 7, 2003, all significant intercompany transactions with NEGT and its subsidiaries were eliminated in consolidation; therefore, no profit or loss resulted from these transactions. Beginning July 8, 2003, the Utility's transactions with NEGT are no longer eliminated in consolidation. The Utility's significant related party transactions and related receivable (payable) balances were as follows:

	Year ended December 31,			Receivable (Payable) Balance Outstanding at Year ended December 31,	
	2004	2003	2002	2004	2003
	(in millions)				
Utility revenues from:					
Administrative services provided to PG&E Corporation	\$ 8	\$ 8	\$ 7	\$ 1	\$ —
Natural gas transportation capacity services provided to NEGT ET	—	8	9	—	—
Contribution in aid of construction received from NEGT	—	—	2	—	—
Trade deposit due from GTNW	—	3	—	—	15
Utility expenses from:					
Administrative services received from PG&E Corporation	\$ 81	\$ 183	\$ 106	\$ (20)	\$ (396)
Interest accrued on pre-petition liabilities due to PG&E Corporation	2	6	8	—	(2)
Administrative services received from NEGT	—	2	2	—	(1)
Software purchases from NEGT ET	—	1	—	—	—
Natural gas commodity services received from NEGT ET	—	10	49	—	—
Natural gas transportation services received from GTNW	43	58	47	—	(8)
Trade deposit due to NEGT ET	—	(7)	7	—	—

As discussed further in Note 2, as of March 31, 2004, PG&E Corporation recorded the impact of the settlement agreement, entered into on December 19, 2003, among PG&E Corporation, the Utility and the CPUC to resolve the Utility's Chapter 11 case, or the Settlement Agreement. The Settlement Agreement precluded the Utility from reimbursing PG&E Corporation for certain Chapter 11 related costs. As such, PG&E Corporation reduced its receivable from the Utility, and the Utility reduced its payable to PG&E Corporation by \$129 million. The transactions were recorded as a contribution of equity to the Utility by PG&E Corporation, net of taxes of \$52 million, and an increase to additional-paid-in-capital by the Utility in the first quarter of 2004.

Property, Plant and Equipment

Property, plant and equipment are reported at their original costs. Original costs include:

- Labor and materials;
- Construction overhead; and
- Capitalized interest or an allowance for funds used during construction, or AFUDC.

As discussed in Note 3, substantially all of the Utility's real property and certain tangible personal property related to the Utility's facilities serve as collateral for the first mortgage bonds, or First Mortgage Bonds.

Capitalized Interest and AFUDC —AFUDC is the estimated cost of debt and equity funds used to finance regulated plant additions that is allowed to be recorded as part of the costs of construction projects. AFUDC is recoverable from customers through rates once the property is placed in service. The Utility had capitalized interest and AFUDC of approximately \$32 million at December 31, 2004 and \$29 million at December 31, 2003. PG&E Corporation on a stand-alone basis did not have any capitalized interest and AFUDC at December 31, 2004 and 2003.

Depreciation —The Utility's composite depreciation rate was 3.42% in 2004, 2003 and 2002.

	Gross Plant	Estimated useful lives
	(in millions)	
Electricity generating facilities	\$ 1,885	15 to 50 years
Electricity distribution facilities	13,962	16 to 58 years
Electricity transmission	3,644	40 to 70 years
Natural gas distribution facilities	4,634	23 to 54 years
Natural gas transportation	2,828	25 to 45 years
Natural gas storage	47	25 to 48 years
Other	3,045	5 to 40 years
Total	\$ 30,045	

The useful lives of the Utility's property, plant and equipment are authorized by the CPUC and the FERC and depreciation expense is included within the recoverable costs of service included in rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated future removal costs, net of any salvage value at retirement. The Utility has a separate rate component for the accrual of its recorded obligation for nuclear decommissioning, which is included in depreciation, amortization and decommissioning expense in the accompanying Consolidated Statements of Operations.

PG&E Corporation and the Utility charge the original cost of retired plant and removal costs less salvage value to accumulated depreciation upon retirement of plant in service for the Utility's lines of business that apply SFAS No. 71, which include electricity and natural gas distribution, electricity generation and transmission, and natural gas transportation and storage. PG&E Corporation and the Utility expense repair and maintenance costs as incurred.

Nuclear Fuel —Property, plant and equipment also includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted average cost. Nuclear fuel in the reactor is amortized based on the amount of energy output.

Capitalized Software Costs —PG&E Corporation and the Utility capitalize costs incurred during the application development stage of internal use software projects to property, plant and equipment. Capitalized software costs totaled \$231 million at December 31, 2004 and \$273 million at December 31, 2003, net of accumulated amortization of approximately \$196 million at December 31, 2004 and \$159 million at December 31, 2003. PG&E Corporation and the Utility amortize capitalized software costs ratably over the expected lives of the projects ranging from 3 to 15 years, commencing upon operational use, in accordance with regulatory recovery requirements.

Impairment of Long-Lived Assets

The carrying values of long-lived assets are evaluated in accordance with the provisions of SFAS No. 144. In accordance with SFAS No. 144, PG&E Corporation and the Utility evaluate the carrying amounts of long-lived assets for impairment whenever events occur or circumstances change that may affect the recoverability or the estimated life of long-lived assets. SFAS No. 144 became effective at the beginning of 2002 and supersedes SFAS No. 121, "Accounting for the Impairment or Disposal of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of," and the accounting and reporting provisions of Accounting Principles Board Opinion No. 30, "Reporting the Results of Operations for a Disposal of a Segment of a Business." The adoption of SFAS No. 144 did not have a material impact on the consolidated financial position, results of operations or cash flows of PG&E Corporation or the Utility. During 2003 and 2002, NEGT recorded certain impairment charges in accordance with SFAS No. 144. See Note 5 for further discussion.

Gains and Losses on Debt Extinguishments

Gains and losses on debt extinguishments associated with regulated operations that are subject to the provisions of SFAS No. 71 are deferred and amortized over the remaining original amortization period of the debt reacquired, consistent with recovery of costs through regulated rates. Gains and losses on debt extinguishments associated with unregulated operations are recognized at the time such debt is reacquired and are reported as interest expense.

Fair Value of Financial Instruments

The fair value of a financial instrument represents the amount at which the instrument could be exchanged in a current transaction between willing parties, other than in a forced sale or liquidation. Significant differences can occur between the fair value and carrying amount of financial instruments that are recorded at historical amounts.

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value disclosures for financial instruments:

- The fair values of cash and cash equivalents, restricted cash and deposits, net accounts receivable, price risk management assets and liabilities, short-term borrowings, accounts payable, customer deposits, the Utility's variable rate pollution control bond loan agreements, Floating Rate First Mortgage Bonds due 2006, and the pollution control bond bridge facilities approximate their carrying values as of December 31, 2004 and 2003;
- The fair values of fixed rate First Mortgage Bonds, fixed rate pollution control loan agreements, rate reduction bonds, and the Utility's preferred stock were determined based on quoted market prices; and
- The fair value of PG&E Corporation's 9.50% Convertible Subordinated debt for which no market quotation is readily available, was determined by a third-party using the present value of future cash flows incorporating estimates of borrowing rates currently available to PG&E Corporation for instruments of similar maturity and the Black-Scholes option valuation model (including a stock volatility assumption of 15-20%).

The carrying amount and fair value of PG&E Corporation's and the Utility's financial instruments are as follows (the table below excludes financial instruments with fair values that approximate their carrying values, as these instruments are presented in the Consolidated Balance Sheets):

	At December 31,			
	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(in millions)			
Long-term debt (Note 3):				
PG&E Corporation				
Convertible subordinated notes ⁽¹⁾	280	738	280	649
Utility	5,632	5,813	4,839	4,905
Rate reduction bonds (Note 4)	870	911	1,160	1,252
Utility preferred stock with mandatory redemption provisions (Note 7)	122	127	137	167

⁽¹⁾ Excludes the estimated fair value of dividend participation rights component on a pre-tax basis of approximately \$91 million at December 31, 2004. See Note 3 for further discussion.

Regulatory Assets

Regulatory assets comprise the following:

	Balance at December 31,	
	2004	2003
	(in millions)	
Settlement Regulatory Asset	\$ 3,188	\$ —
Utility retained generation regulatory assets	1,181	—
Rate reduction bond assets	741	1,054
Regulatory assets for deferred income tax	490	324
Unamortized loss, net of gain, on reacquired debt	345	277
Environmental compliance costs	192	139
Post-transition period contract termination costs	142	151
Regulatory assets associated with plan of reorganization	182	—
Other, net	65	56
Total regulatory assets	\$ 6,526	\$ 2,001

Amortization of regulatory assets are charged to expense during the period that the costs are reflected in regulated revenues. In light of the satisfaction of various conditions to the implementation of the plan of reorganization, the accounting probability standard required to be met under SFAS No. 71 in order for the Utility to recognize the regulatory assets provided under the Settlement Agreement (as described in Note 2) was met as of March 31, 2004. Therefore, the Utility recorded the \$3.7 billion, pre-tax (\$2.2 billion, after-tax), regulatory asset established under the Settlement Agreement, or the Settlement Regulatory Asset, and \$1.2 billion, pre-tax (\$0.7 billion, after-tax), for the Utility retained generation regulatory assets in the first quarter of 2004 (see Note 2 for further discussion). As of December 31, 2004, the Utility has recorded pre-tax offsets to the Settlement Regulatory Asset of approximately \$309 million (\$183 million after-tax) for supplier settlements and approximately \$233 million (\$138 million, after-tax) for amortization of the Settlement Regulatory Asset.

The Utility's regulatory asset related to rate reduction bonds is amortized simultaneously with the amortization of the rate reduction bonds liability, and is expected to be recovered by the end of 2007. The Utility's regulatory assets related to deferred income tax will be recovered over the period of reversal of the accumulated deferred taxes to which they relate. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income tax-related regulatory assets over periods ranging from 1 to 37 years. The Utility's regulatory asset related to the unamortized loss, net of gain, on reacquired debt will be recovered over the remaining original amortization period of the reacquired debt over periods ranging from 1 to 22 years. The Utility's regulatory asset related to environmental compliance represents the portion of the Utility's environmental liability recognized at the end of the period in excess of the amount that has been recovered through rates charged to customers. This amount will be recovered in future rates. The Utility's regulatory assets associated with the plan of reorganization will be recovered over periods ranging from 2 to 30 years. The Utility's regulatory asset relating to post-transition period contract termination costs are being amortized and collected in rates on a straight-line basis until the end of September 2014, the contract's original termination date. This amount will be recovered in future rates.

In general, the Utility does not earn a return on regulatory assets where the related costs do not accrue interest. Accordingly, the only regulatory asset on which the Utility earns a return on is the regulatory assets relating to the Settlement Agreement, retained generation and unamortized loss, net of gain on reacquired debt.

Regulatory Liabilities

Regulatory liabilities comprise the following:

	Balance at December 31,	
	2004	2003
	(in millions)	
Cost of removal obligation	\$ 1,990	\$ 1,810
Asset retirement costs	700	584
Employee benefit plans	687	925
Public purpose programs	191	185
Rate reduction bonds	182	175
Surcharge liability	105	125
Other	180	175
Total regulatory liabilities	\$ 4,035	\$ 3,979

The Utility's regulatory liabilities related to costs of removal represent revenues collected for asset removal costs that the Utility expects to incur in the future. The Utility's regulatory liabilities related to employee benefit plan expenses represent the cumulative differences between expenses recognized for financial accounting purposes and expenses recognized for ratemaking purposes. These balances will be charged against expense to the extent that future financial accounting expenses exceed amounts recoverable for regulatory purposes. The regulatory liability associated with over-recovery of asset retirement costs represents timing differences between the recognition of nuclear decommissioning obligations in accordance with GAAP applicable to non-regulated entities under SFAS No. 143, and the amounts recognized for ratemaking purposes. The Utility's regulatory liability related to public purpose programs represents revenues designated for public purpose program costs that are expected to be incurred in the future. The Utility's regulatory liability for rate reduction bonds represents the deferral of over-collected revenue associated with the rate reduction bonds that the Utility expects to return to customers in the future. For electricity distribution and generation, the Utility collected electricity

revenue and surcharges subject to refund under the frozen rate structure in 2003. The surcharge liability represents the amount of electricity revenue to be refunded.

Regulatory Balancing Accounts

Sales balancing accounts accumulate differences between revenues and the Utility's authorized revenue requirements. Cost balancing accounts accumulate differences between incurred costs and authorized revenue requirements. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being credited to customers are recorded as regulatory balancing account liabilities. The Utility's regulatory balancing accounts accumulate balances until they are refunded to or received from the Utility's customers through authorized rate adjustments.

During the California energy crisis, the Utility could not conclude that power generation and procurement-related balancing accounts met the probability requirements of SFAS No. 71. However, the Utility was able to continue to record balancing accounts associated with its electricity transmission and distribution and natural gas transportation businesses.

The Utility's current regulatory balancing account assets comprise the following:

	Balance at December 31,	
	2004	2003
	(in millions)	
Natural gas revenue balancing accounts	\$ 76	\$ 20
Natural gas cost balancing accounts	95	58
Electricity revenue balancing accounts	151	75
Electricity distribution cost balancing accounts	699	95
Total	\$ 1,021	\$ 248

The Utility's current regulatory balancing account liabilities comprise the following:

	Balance at December 31,	
	2004	2003
	(in millions)	
Natural gas revenue balancing accounts	\$ —	\$ 9
Natural gas cost balancing accounts	34	162
Electricity transmission and distribution revenue balancing accounts	116	6
Electricity transmission cost balancing accounts	219	9
Total	\$ 369	\$ 186

The Utility expects to collect from or refund to its customers the balances included in current balancing accounts receivable and payable within the next twelve months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next twelve months are included in non-current regulatory assets and liabilities.

Revenue Recognition

Electricity revenues, which are comprised of generation, transmission, and distribution services, are billed to the Utility's customers at the CPUC-approved "bundled" electricity rate. Natural gas revenues, which are comprised of transmission and distribution services, are also billed at CPUC-approved rates. The Utility's revenues are recognized as natural gas and electricity are delivered, and include amounts for services rendered but not yet billed at the end of each year.

As further discussed in Note 12, in January 2001, the California Department of Water Resources, or DWR, began purchasing electricity to meet the portion of demand of the California investor-owned electric utilities that was not being satisfied from their own generation facilities and existing electricity contracts. Under California law, the DWR is deemed to sell the electricity directly to the Utility's retail customers, not to the Utility. Therefore, the Utility acts as a pass-through entity for electricity purchased by the DWR on behalf of its customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts from its electricity revenues the amounts passed through to the DWR. The pass-through amounts are based on the quantities of electricity provided by the DWR that are consumed by customers at the CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues in its Consolidated Statements of Operations.

Allowance for Doubtful Accounts

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record its accounts receivables at an estimated net realizable value. The allowance is determined based upon a variety of factors, such as historical write-off experience, delinquency rates, current economic conditions and our assessment of customer collectibility. If circumstances related to the Utility's assumptions change, recoverability estimates are adjusted accordingly.

Accounting for Price Risk Management Activities

PG&E Corporation, through the Utility, engages in price risk management activities for non-trading purposes. Price risk management activities include the continuation of power forward contracts that were in existence before the Utility's Chapter 11 proceeding, new power contracts entered into since January 1, 2003 when the Utility resumed procurement of electricity, contracts related to the natural gas and nuclear fuel portfolio, and interest rate hedges related to the issuance of debt under the Utility's plan of reorganization.

Derivative instruments include most forward contracts, futures, swaps, options and other contracts. (Some contracts are accounted for as leases.) Derivative instruments designated as cash flow hedges are entered into to hedge variable price risk associated with the purchase and sale of commodities or to hedge variable interest rates on long-term debt. Additionally, derivative instruments may be eligible for a scope exclusion as further discussed below. For derivative instruments that are not designated as hedges or that are not eligible for a scope exclusion, they are adjusted to fair value through income.

Derivative instruments recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets are presented in other current assets or other current liabilities. For derivative instruments designated as cash flow hedges associated with non-regulated operations, unrealized gains or losses related to the effective portion of the change in the fair value of the derivative instrument are recorded in accumulated other comprehensive income until the hedged item is recognized in earnings. The ineffective portion of the change in the fair value of the derivative instrument is recognized immediately in earnings. For derivative instruments designated as cash flow hedges associated with the Utility's regulated operations, unrealized gains and losses related to the effective and ineffective portions of the change in the fair value of the derivative instrument to the extent they are recoverable through regulated rates, are deferred and recorded in regulatory accounts.

Hedge accounting is discontinued prospectively if it is determined that the derivative instrument no longer qualifies as an effective hedge, or when the forecasted transaction is no longer probable of occurring. If hedge accounting is discontinued the derivative instrument continues to be reflected at fair value, with any subsequent changes in fair value recognized immediately in earnings. Gains and losses related to a derivative instrument that were previously recorded in accumulated other comprehensive income will remain there until the hedged item is recognized in earnings, unless the forecasted

transaction is probable of not occurring, whereupon the gains and losses from the derivative instrument will be immediately recognized in earnings. The gains and losses deferred in accumulated other comprehensive income are recognized in earnings when the hedged item matures or is exercised.

Net realized and unrealized gains or losses on derivative instruments are included in various lines on PG&E Corporation's and the Utility's Consolidated Statements of Operations, including cost of electricity, cost of natural gas and interest expense. Cash inflows and outflows associated with the settlement of price risk management activities are recognized in operating cash flows on PG&E Corporation's and the Utility's Consolidated Statements of Cash Flows.

The fair value of contracts is estimated using the mid-point of quoted bid and ask forward prices, including quotes from counterparties, brokers, electronic exchanges and published indices, supplemented by online price information from news services. When market data is not available, models are used to estimate fair value.

The Utility has derivative instruments for the physical delivery of commodities transacted in the normal course of business as well as non-financial assets that are not exchange-traded. These derivative instruments are exempt from the requirements of SFAS No. 133 under the normal purchase and sales and non-exchange traded contract exceptions, and are not reflected on the balance sheet at fair value. They are recorded and recognized in income using accrual accounting. Therefore, revenues are recognized as earned and expenses are recognized as incurred.

The Utility has certain commodity contracts for the purchase of nuclear fuel and core gas transportation and storage contracts that are not derivative instruments and are not reflected on the balance sheet at fair value. Revenues are recorded as earned and expenses are recognized as incurred.

Stock-Based Compensation

PG&E Corporation and the Utility apply the intrinsic-value method prescribed in Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," in accounting for employee stock-based compensation, as allowed by SFAS No. 123, "Accounting for Stock-Based Compensation," or SFAS No. 123, as amended by SFAS No. 148, "Accounting for Stock-Based Compensation—Transition and Disclosure, an Amendment of FASB Statement No. 123," or SFAS No. 148. Under the intrinsic-value method, PG&E Corporation and the Utility do not recognize any compensation expense for stock options, as the exercise price is equal to the fair market value of a share of PG&E Corporation common stock at the time the options are granted.

The tables below show the effect on net income and earnings per share for PG&E Corporation and the Utility had it elected to account for its stock-based compensation plans using the fair-value

method under SFAS No. 123 and using the valuation assumptions disclosed in Note 10, for the years ended December 31, 2004, 2003, and 2002:

	Years ended December 31,		
	2004	2003	2002
	(in millions, except per share amounts)		
Net earnings (loss):			
As reported	\$ 4,504	\$ 420	\$ (874)
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(14)	(19)	(20)
Pro forma	\$ 4,490	\$ 401	\$ (894)
Basic earnings (loss) per share:			
As reported	\$ 10.80	\$ 1.04	\$ (2.30)
Pro forma	10.77	0.99	(2.35)
Diluted earnings (loss) per share:			
As reported	10.57	1.02	(2.27)
Pro forma	10.59	0.97	(2.33)

If compensation expense had been recognized using the fair value-based method under SFAS No. 123, the Utility's pro forma consolidated earnings would have been as follows:

	Year ended December 31,		
	2004	2003	2002
	(in millions)		
Net earnings:			
As reported	\$ 3,961	\$ 901	\$ 1,794
Deduct: Total stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	(8)	(8)	(7)
Pro forma	\$ 3,953	\$ 893	\$ 1,787

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of an enterprise that results from transactions and other economic events, other than

transactions with shareholders. The following table sets forth the changes in each component of accumulated other comprehensive income (loss):

	Hedging Transactions in Accordance with SFAS No. 133	Foreign Currency Translation Adjustment	Retirement Plan Remeasurement	Other	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2001	\$ 36	\$ (5)	\$ —	\$ (1)	\$ 30
Period change in:					
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	(139)	—	—	—	(139)
Net reclassification to earnings	13	—	—	—	13
Other	—	2	—	1	3
Balance at December 31, 2002	(90)	(3)	—	—	(93)
Period change in:					
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	(8)	—	—	—	(8)
Net reclassification to earnings	17	—	—	—	17
Other	—	3	(4)	—	(1)
Balance at December 31, 2003	(81)	—	(4)	—	(85)
Period change in:					
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	3	—	—	—	3
NEGT losses reclassified to earnings upon elimination of equity interest by PG&E Corporation	77	—	—	—	77
Other	—	—	—	1	1
Balance at December 31, 2004	\$ (1)	\$ —	\$ (4)	\$ 1	\$ (4)

Accumulated other comprehensive income (loss) included losses related to discontinued operations of approximately \$77 million at December 31, 2003 and approximately \$93 million at December 31, 2002. During the fourth quarter of 2004, the remaining losses of approximately \$77 million included in accumulated other comprehensive income (loss) were recognized in connection with PG&E Corporation's elimination of its equity interest in NEGTE.

Accounting Pronouncements Issued But Not Yet Adopted

Share-Based Payment Transactions

In December 2004, the FASB issued Statement No. 123 (revised December 2004), "Share-Based Payment," or SFAS No. 123R. SFAS No. 123R requires that the cost resulting from all share-based payment transactions be recognized in the financial statements and establishes a fair-value measurement objective in determining the value of such a cost. SFAS No. 123R will be effective for the third quarter of 2005. PG&E Corporation and the Utility are currently evaluating the impact of SFAS No. 123R on their Consolidated Financial Statements.

Inventory Costs

In December 2004, the FASB issued Statement No. 151, "Inventory Costs an amendment of ARB No. 43, Chapter 4", or SFAS No. 151. The guidance clarifies that the allocation of fixed production overhead to inventory is based on normal capacity. Abnormal amounts of idle facility, excess freight, handling costs and spoilage should be recognized as a current period charge. SFAS No. 151 will be effective January 1, 2006. The adoption of SFAS No. 151 is not expected to have a material effect on the financial position or results of operations of either PG&E Corporation or the Utility.

NOTE 2: THE UTILITY'S CHAPTER 11 FILING

As a result of the California energy crisis, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 on April 6, 2001. The Utility retained control of its assets and was authorized to operate its business as a debtor-in-possession during its Chapter 11 proceeding. PG&E Corporation and the subsidiaries of the Utility, including PG&E Funding LLC, (which issued rate reduction bonds) and PG&E Holdings LLC (which holds stock of the Utility), were not included in the Utility's Chapter 11 proceeding. The Utility recorded its estimate of all valid claims of approximately \$9.5 billion as liabilities subject to compromise at December 31, 2003, including interest on disputed claims and approximately \$2.7 million of long-term debt.

Emergence From Chapter 11

On April 12, 2004, the Utility emerged from Chapter 11 when its plan of reorganization became effective, or the Effective Date. The plan of reorganization incorporated the terms of the Settlement Agreement approved by the CPUC on December 18, 2003, and entered into among the CPUC, the Utility and PG&E Corporation on December 19, 2003, to resolve the Utility's Chapter 11 proceeding. Although the Utility's operations are no longer subject to the oversight of the bankruptcy court, the bankruptcy court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Settlement Agreement, (2) the plan of reorganization, and (3) the bankruptcy court's December 22, 2003 order confirming the plan of reorganization. In addition, the bankruptcy court retains jurisdiction to resolve remaining disputed claims.

In anticipation of its emergence from Chapter 11, the Utility consummated its public offering of \$6.7 billion of First Mortgage Bonds on March 23, 2004. Upon the Effective Date the Utility paid all valid claims, deposited funds into escrow accounts for the payment of disputed claims upon their

resolution, reinstated certain obligations, and paid other obligations. The following table summarizes the sources and uses of funds on the Effective Date:

Sources		Uses	
(in millions)			
First Mortgage Bonds	\$ 6,700	Payments to Creditors	\$ 8,394
Term Loans	799	Disputed Claims Escrow	1,843
Accounts Receivable Financing Facility	350		
Total Debt Financing	7,849		
Cash Used to Pay Claims	2,388		
Sources of Funds for Claims	10,237	Uses of Funds for Claims	10,237
Reinstated Pollution Control Bond-Related Obligations	814	Reinstated Pollution Control Bond-Related Obligations	814
Reinstated Preferred Stock	421	Reinstated Preferred Stock	421
Cash on Hand	225	Preferred Dividends	93
		Environmental Measures	10
		Transaction Costs	122
Total Sources of Funds	\$ 11,697	Total Uses of Funds	\$ 11,697

In connection with the Utility's emergence from Chapter 11, the Utility received investment-grade issuer credit ratings of Baa3 from Moody's Investors Service, or Moody's, and BBB- from Standard & Poor's, or S&P.

On July 15, 2004, the U.S. District Court for the Northern District of California, or the District Court, dismissed the appeals of the bankruptcy court's order confirming the plan of reorganization that had been filed by the two CPUC commissioners who did not vote to approve the Settlement Agreement. These two commissioners appealed the District Court's order to the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit. An appeal of the confirmation order filed by the City of Palo Alto remains pending at the District Court. PG&E Corporation and the Utility believe the appeals of the confirmation order are without merit.

In addition, on April 15, 2004, the City and County of San Francisco, or CCSF, and Aglet Consumer Alliance, or Aglet, each filed a petition with the California Court of Appeal seeking review of the CPUC's December 18, 2003 decision approving the Settlement Agreement and the CPUC's March 16, 2004 decision denying applications for rehearing of its December 18, 2003 decision. CCSF and Aglet allege that the Settlement Agreement violates California law, among other claims. CCSF requests that the appellate court hear and review the CPUC's decisions, approving the Settlement Agreement and Aglet requests that the CPUC's decisions be overturned. Three California state senators have filed a brief in support of the CCSF and Aglet petitions. The California Court of Appeal has not yet acted on the petitions. PG&E Corporation and the Utility believe the petitions are without merit and should be denied.

Under applicable federal precedent, once the plan of reorganization has been "substantially consummated," any pending appeals of the confirmation order should be dismissed. If, notwithstanding this federal precedent, the bankruptcy court's confirmation order or the Settlement Agreement is subsequently overturned or modified, PG&E Corporation and the Utility's financial condition and results of operations could be materially adversely affected.

Financial Summary of the Settlement Agreement

In light of the satisfaction of various conditions to the implementation of the plan of reorganization, including the consummation of the public offering of the First Mortgage Bonds, the

receipt of investment grade credit ratings, and final CPUC approval of the Settlement Agreement, the accounting probability standard required to be met under SFAS No. 71, in order for the Utility to recognize the regulatory assets provided under the Settlement Agreement (as described below), was met as of March 31, 2004. Therefore, the Utility recorded the \$2.2 billion, after-tax (\$3.7 billion, pre-tax) Settlement Regulatory Asset, and \$0.7 billion, after-tax (\$1.2 billion, pre-tax), for the Utility retained generation regulatory assets, as summarized in the table below and discussed further in the paragraphs below:

	Settlement Regulatory Asset	Utility Retained Generation Regulatory Assets	Total
	(in millions)		
Authorized, pre-tax, January 1, 2004	\$ 3,730	\$ 1,249	\$ 4,979
Amortization from January 1 to March 31, 2004	(58)	(21)	(79)
Recognition of regulatory assets, pre-tax, March 31, 2004	3,672	1,228	4,900
Deferred income taxes	(1,496)	(500)	(1,996)
Recognition of regulatory assets, after tax, March 31, 2004	\$ 2,176	\$ 728	\$ 2,904

Settlement Regulatory Asset

- The Settlement Agreement established a \$2.2 billion, after-tax, regulatory asset (which is equivalent to an approximately \$3.7 billion, pre-tax, regulatory asset) as a new, separate and additional part of the Utility's rate base that is being amortized on a "mortgage-style" basis over nine years beginning January 1, 2004. The Utility recognized a one-time, non-cash gain of \$3.7 billion, pre-tax, for the Settlement Regulatory Asset in the first quarter of 2004. The Settlement Agreement requires the Utility to reduce the after-tax Settlement Regulatory Asset for any refunds, claims offsets, or other credits that the Utility receives from energy suppliers relating to specified electricity procurement costs incurred during the California energy crisis. As discussed in Note 1, as of December 31, 2004, the Utility has recorded offsets to the Settlement Regulatory Asset of approximately \$309 million, pre-tax (\$183 million, after-tax) for supplier settlements and collected approximately \$233 million, pre-tax (\$138 million, after-tax) for amortization of the Settlement Regulatory Asset.
- The Settlement Agreement authorized the Utility to earn a rate of return on its equity component of the unamortized balance of the Settlement Regulatory Asset of no less than 11.22% annually for its nine-year term. In February 2005, the Utility completed a refinancing of the after-tax balance of the Settlement Regulatory Asset supported by a dedicated rate component as discussed below. The Utility will no longer earn this 11.22% rate of return on the Settlement Regulatory Asset, as it is no longer part of rate base. The equity and debt components of the Utility's rate of return will be replaced with the lower interest rate of the securitized debt.

Utility Retained Generation Regulatory Assets

- In the Settlement Agreement, the CPUC deemed the Utility's adopted electricity generation rate base in a 2002 proceeding to be just and reasonable and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. Accordingly, the Utility recognized a one-time, non-cash gain of \$1.2 billion, pre-tax, for the retained generation regulatory assets in the first quarter of 2004. The individual components of the regulatory assets are amortized over their respective lives, with a weighted average life of approximately 16 years. The Utility retained generation regulatory assets will earn an authorized rate of return on its equity component of 11.22% in 2004 and 2005.

Ratemaking Matters

- In the Settlement Agreement, the CPUC agreed to set the Utility's capital structure and authorized return on equity in its annual cost of capital proceedings in its usual manner. However, from January 1, 2004 until Moody's has issued an issuer rating for the Utility of not less than A3 or S&P has issued a long-term issuer credit rating for the Utility of not less than A-, the Utility's authorized return on equity will be no less than 11.22% per year and its authorized equity ratio for ratemaking purposes will be no less than 52%. For 2004 and 2005, the Utility's authorized equity ratio will be the greater of the proportion of equity approved in the Utility's 2004 and 2005 cost of capital proceedings, or 48.6%. In December 2004, the CPUC issued the Utility's cost of capital decision authorizing an equity ratio of 49.0% for 2004 and 52% for 2005.
- The CPUC also agreed to act promptly on certain of the Utility's pending ratemaking proceedings. The outcome of these proceedings may result in the establishment of additional regulatory assets on the Utility's Consolidated Balance Sheet.

Environmental Measures

- In the Settlement Agreement, the Utility agreed to encumber with conservation easements or donate approximately 140,000 acres of land to public agencies or non-profit conservation organizations.
- The Utility has established the Pacific Forest and Watershed Stewardship Council to oversee the environmental enhancements associated with these lands. The Utility has agreed to fund the council with \$100 million in cash over 10 years. The Utility paid two installments of \$10 million each in October 2004 and in January 2005 to this council. As of December 31, 2004, the Utility has recorded a \$75 million liability based on the discounted present value of future cash payments to this council. The Utility will be entitled to recover these payments in rates. Therefore, the Utility recognized an offsetting regulatory asset and the recognition of the obligation had no impact on the Utility's results of operations.
- The Utility has also established a California non-profit corporation that is dedicated to support research and investment in clean energy technology, primarily in the Utility's service territory. The Utility agreed to fund this corporation with \$30 million payable over five years. The Utility paid two installments of \$2 million each in July 2004 and in January 2005 to this corporation. These contributions may not be recovered in rates. In the first quarter of 2004, the Utility recorded a \$27 million, pre-tax charge to earnings based on the discounted present value of future cash payments.

Of the approximately 140,000 acres referred to above, approximately 44,000 acres may be either donated or encumbered with conservation easements. The remaining land contains the Utility's or a joint licensee's hydroelectric generation facilities and may only be encumbered with conservation easements. In the first quarter of 2004, the Utility recorded a \$1 million, pre-tax charge to earnings associated with the land donation obligation.

Fees and Expenses

The Settlement Agreement required the Utility to reimburse the CPUC for its professional fees and expenses incurred in connection with the Chapter 11 proceeding. These amounts will be recovered from customers over a reasonable time of up to four years. As of December 31, 2004, the Utility had a regulatory asset of approximately \$24 million relating to the CPUC reimbursable fees and expenses. In addition, one of the terms of the Settlement Agreement precluded the Utility from reimbursing PG&E Corporation for certain Chapter 11 related costs. As such, PG&E Corporation reduced its receivable

from the Utility, and the Utility reduced its payable to PG&E Corporation, by approximately \$128 million. The transactions were recorded as a contribution of equity to the Utility by PG&E Corporation, net of taxes, and an increase to additional paid-in capital by the Utility in the first quarter 2004.

Refinancing Supported by a Dedicated Rate Component

In connection with the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the remaining unamortized balance of the Settlement Regulatory Asset and related federal, state, and franchise taxes, in an aggregate amount of up to \$3.0 billion, in two separate series up to one year apart, to be secured by a dedicated rate component, or DRC, provided that authorizing legislation was adopted and certain conditions were met. In June 2004, the California Governor signed into law Senate Bill 772, which authorizes the issuance of energy recovery bonds, or ERBs, to be secured by the establishment of a DRC, to refinance the Settlement Regulatory Asset and related taxes.

In November 2004, the CPUC approved the Utility's application for a wholly owned subsidiary to issue ERBs. In December 2004, the Utility received a favorable private letter ruling from the IRS. After satisfaction of all conditions, on February 10, 2005, PG&E Energy Recovery Funding LLC, or PERF, a limited liability company wholly owned and consolidated by the Utility (but legally separate from the Utility), issued the first series of ERBs for approximately \$1.9 billion. The Utility, as servicer, will collect DRC charges from customers and remit collected amounts to PERF to enable PERF to pay principal and interest on the ERBs. The proceeds of the first series of ERBs were paid by PERF to the Utility and will be used by the Utility to refinance the remaining unamortized after-tax balance of the Settlement Regulatory Asset through the redemption and repurchase of higher cost equity and debt. The proceeds of the second series of ERBs, anticipated to be issued in November 2005 in an aggregate amount of up to \$1.1 billion, will be paid by PERF to the Utility to pre-fund the Utility's recovery through rates of the tax payments that will be due as the Utility collects the DRC over the term of the first series of ERBs to pay principal.

Chapter 11 Claims

The following table summarizes the disposition of the net creditor claims made in the Utility's Chapter 11 proceeding, the amount of funds held in escrow for the resolution of disputed claims and the disputed claims accrued by the Utility at December 31, 2004:

	(in billions)
Total filed claims in the Utility's Chapter 11 proceeding	\$ 51.7
ISO, PX and generator claims disallowed	(8.2)
Other claims disallowed by the bankruptcy court	(25.4)
Claims objected to by the Utility and pending before the bankruptcy court	(0.1)
Pass-through claims, including environmental, pending litigation and tort claims ⁽¹⁾	(4.7)
Principal payments made prior to the effectiveness of the plan of reorganization	(2.3)
Claims settled with the cancellation of bonds owned by the Utility	(0.3)
Payments on claims on and after the effectiveness of the plan of reorganization ⁽²⁾	(8.2)
Reinstated Pollution Control Bonds	(0.8)
Amount retained in escrow for remaining disputed claims—principal, at December 31, 2004	\$ 1.7
Disputed claims not accrued by the Utility	(0.1)
Net disputed claims accrued by the Utility at December 31, 2004	\$ 1.6

⁽¹⁾ The Utility has analyzed these claims and has recorded reserves for such claims that are included in the Utility's undiscounted environmental remediation liability of approximately \$327 million at

December 31, 2004 and the Utility's provision for legal matters of approximately \$200 million at December 31, 2004, as discussed below in Note 12.

- (2) The Utility also made payments of approximately \$0.2 billion for interest and bank premiums upon the effectiveness of the plan of reorganization.

As of December 31, 2004, the Utility had accrued approximately \$1.6 billion for remaining net disputed claims, consisting of approximately \$2.1 billion of accounts payable-disputed claims primarily payable to the ISO and the Power Exchange, or the PX, offset by an accounts receivable amount from the ISO and the PX of approximately \$0.5 billion. As disclosed in the table above, the Utility held \$1.7 billion in escrow for the payment of remaining disputed claims as of December 31, 2004. Although the Utility was required to hold \$1.7 billion in escrow, the Utility does not believe it is probable that it will be found liable for approximately \$0.1 billion of the \$1.7 billion of the disputed claims and, therefore, in accordance with SFAS No. 5, "Accounting for Contingencies," or SFAS No. 5, the Utility has not recorded a liability in its financial statements for this amount. Upon resolution of these claims and under the terms of the Settlement Agreement, any refunds, claims offsets or other credits that the Utility receives from energy suppliers will be returned to customers.

NOTE 3: DEBT

Long-Term Debt

The following table summarizes PG&E Corporation's and the Utility's long-term debt that matures in one year or more from the date of issuance:

	December 31,	
	2004	2003
	(in millions)	
PG&E Corporation		
Senior secured notes, 6 ⁷ / 8 %, due 2008	\$ —	\$ 600
Convertible subordinated notes, 9.50%, due 2010	280	280
Other long-term debt	1	3
Less: current portion	(1)	—
	<u>280</u>	<u>883</u>
Utility		
First and refunding mortgage bonds:		
5.85% to 8.80% bonds, due 2004-2026	—	2,764
Unamortized discount, net of premium	—	(23)
	<u>—</u>	<u>2,741</u>
Total first and refunding mortgage bonds	—	2,741
First mortgage bonds:		
2.72% to 6.05% bonds, due 2006-2034	6,200	—
Unamortized discount, net of premium	(17)	—
	<u>6,183</u>	<u>—</u>
Total first mortgage bonds	6,183	—
Pollution control loan agreements, variable rates, due 2007	614	—
Pollution control loan agreement, 5.35%, due 2016	200	—
Pollution control bond agreements, 3.50%, due 2007	345	—
Pollution control bond bridge facilities, variable rates, due 2005	454	—
Other	4	—
Less: current portion	(757)	(310)
	<u>7,043</u>	<u>2,431</u>
Total consolidated long-term debt, net of current portion	<u>\$ 7,323</u>	<u>\$ 3,314</u>
Long-term debt subject to compromise:		
Senior notes, 10.75%, due 2005	\$ —	\$ 680
Pollution control loan agreements, variable rates, due 2026	—	614
Pollution control loan agreements, 5.35%, due 2016	—	200
Unsecured medium-term notes, 6.94% to 9.58%, due 2004-2014	—	287
Deferrable interest subordinated debentures, 7.90%, due 2025	—	300
Other	—	17
	<u>—</u>	<u>2,098</u>
Total long-term debt subject to compromise	<u>\$ —</u>	<u>\$ 2,098</u>

PG&E Corporation

Senior Secured Notes

On November 15, 2004, PG&E Corporation redeemed the \$600 million of 6 ⁷ / 8 % Senior Secured Notes due 2008, or Senior Secured Notes, in full. Redemption of the Senior Secured Notes required approximately \$664.5 million of PG&E Corporation's cash, which included a redemption premium of approximately \$50.7 million and \$13.8 million of interest accrued since the last interest payment date.

As a result of the Senior Secured Notes redemption, PG&E Corporation wrote off approximately \$14.6 million of unamortized loan fees in the three months ended December 31, 2004.

Convertible Subordinated Notes

PG&E Corporation currently has outstanding \$280 million of 9.50% Convertible Subordinated Notes that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,655 shares of common stock of PG&E Corporation, at a conversion price of \$15.09 per share. The conversion price is subject to adjustment should a significant change occur in the number of PG&E Corporation's outstanding common shares. To date, the conversion price has not required adjustment. In addition, the terms of the Convertible Subordinated Notes entitle the note holders to participate in any dividends declared and paid on PG&E Corporation's common shares based on their equity conversion value. The holders have a one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including liquidated damages and pass-through dividends, if any).

In accordance with SFAS No. 133, the dividend participation rights component is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and marked to market on PG&E Corporation's Consolidated Statements of Operations as a non-operating expense (in Other expense, net), and reflected at fair value on PG&E Corporation's Consolidated Balance Sheet at December 31, 2004 as \$76 million of non-current liability (in Non-current liabilities—other) and \$15 million of current liability (in Current liabilities—other). At December 31, 2004, the total estimated fair value of the dividend participation rights component on a pre-tax basis was approximately \$91 million.

Warrants

Concurrent with the negotiation of an amendment of a previously existing credit agreement in June 2002, now paid in full, warrants to purchase 2,397,541 shares of PG&E Corporation's common stock were issued, at an exercise price of \$0.01 per share. In October 2002, the above mentioned credit agreement was amended to increase the size of the facility by \$300 million to a total of \$720 million. In connection with this amendment, PG&E Corporation issued to affiliates of the lenders additional warrants to purchase 2,669,390 shares of PG&E Corporation's common stock, with an exercise price of \$0.01 per share. At December 31, 2004, 347,912 of these warrants were outstanding and exercisable with an expiration date of September 2, 2006.

Utility

In March 2004, in connection with the implementation of the plan of reorganization, the Utility issued \$6.7 billion of First Mortgage Bonds and together with its consolidated subsidiaries, entered into \$2.9 billion of credit facilities. The Utility obtained an interim \$400 million cash collateralized letter of credit facility, which was terminated on the Effective Date and the letters of credit then outstanding were transferred to the \$850 million revolving credit facility.

First Mortgage Bonds

On March 23, 2004, the Utility closed a public offering of \$6.7 billion of First Mortgage Bonds. The First Mortgage Bonds were offered in multiple tranches consisting of 3.60% First Mortgage Bonds due March 1, 2009 in the principal amount of \$600 million, 4.20% First Mortgage Bonds due March 1, 2011 in the principal amount of \$500 million, 4.80% First Mortgage Bonds due March 1, 2014 in the principal amount of \$1 billion, 6.05% First Mortgage Bonds due March 1, 2034 in the principal amount of \$3 billion, and Floating Rate First Mortgage Bonds due April 3, 2006 in the principal amount of

\$1.6 billion. The Utility received proceeds of \$6.7 billion from the offering, net of a discount of \$18 million. The interest rate for the Floating Rate First Mortgage Bonds is based on the three-month London Interbank Offered Rate, or LIBOR, plus 0.70%, which resets quarterly. The next reset date is April 3, 2005. For 2004, the average interest rate on the Floating Rate First Mortgage Bonds was 4.8%.

On October 3, 2004, the Utility partially redeemed Floating Rate First Mortgage Bonds due in 2006 in the aggregate principal amount of \$500 million. On January 3, 2005, the Utility partially redeemed Floating Rate First Mortgage Bonds due in 2006 in the aggregate principal amount of \$300 million. In addition, the Utility plans to use a portion of the energy recovery bond proceeds to defease \$600 million of Floating Rate First Mortgage Bonds by the end of February 2005.

In addition, approximately \$2.5 billion of additional First Mortgage Bonds have been issued as security to various banks and insurance companies under the following agreements (1) the Utility's \$620 million letters of credit backing pollution control bonds, (2) the Utility's reimbursement obligation under an insurance policy relating to \$200 million in pollution control bonds that were issued for the benefit of the Utility, (3) the Utility's \$345 million loan agreements with the California Pollution Control Financing Authority, or the CPCFA, (4) the Utility's \$454 million reimbursement agreements for pollution control bond bridge facilities, and (5) the Utility's \$850 million working capital facility.

The First Mortgage Bonds are secured by a first lien, subject to permitted exceptions, on substantially all of the Utility's real property and certain tangible personal property related to the Utility's facilities. Subject to certain conditions, the Utility will be entitled to terminate the lien and eliminate all terms and conditions relating to collateral for the First Mortgage Bonds on the release date. In general, the release date will occur when the Utility provides written evidence to the trustee of the First Mortgage Bonds that the ratings on the Utility's long-term unsecured debt obligations following the release date would at least equal the (1) initial ratings assigned by Moody's and S&P on the First Mortgage Bonds, or (2) comparable ratings by any other nationally recognized rating agency or agencies selected by the Utility if either Moody's or S&P do not then rate the Utility's long-term unsecured debt obligations. The First Mortgage Bonds received initial investment grade credit ratings of Baa2 from Moody's and BBB from S&P.

If the lien securing the First Mortgage Bonds is released, the indenture will limit the ability of the Utility and its significant subsidiaries to incur secured debt and enter into sale and leaseback transactions.

Pollution Control Bonds

Variable Rate and 5.35% Pollution Control Loan Agreements

Under pollution control loan agreements, the Utility is obligated to reimburse the CPCFA for funds received by the Utility from the issuance of the CPCFA's pollution control bonds for the benefit of the Utility. The principal amount of these loan obligations totaled \$814 million at December 31, 2004. Interest rates on \$614 million of \$814 million of the obligations are variable. For 2004, the average variable interest rates ranged from 1.19% to 1.21%. The interest rate on the remaining \$200 million of the obligations is fixed at 5.35%.

The CPCFA pollution control bonds in the principal amount of \$200 million are backed by bond insurance. The CPCFA pollution control bonds in the principal amount of \$614 million are backed by letters of credit of \$620 million. The Utility's reimbursement obligations are supported by \$820 million in First Mortgage Bonds that have been issued to the bond insurer and letter of credit banks. These bank agreements supplying the letters of credit include a covenant requiring the Utility to maintain, as of the end of each fiscal quarter ending after the Effective Date, a debt to capitalization ratio of at most 65%.

Drawings for interest due under the loan agreements are made under these letters of credit on each scheduled interest payment date, which is the first business day of each month. On the same day, the Utility pays the amount of the draw to the letter of credit banks per the terms of the reimbursements agreements. The letters of credit are then reinstated to the full amount of their initial commitments.

Pollution Control Bond Term Loan Facility and 3.5% Pollution Control Loan Agreements

On the Effective Date, the Utility entered into a \$345 million term loan facility that was used to fund the Utility's purchase, in lieu of redemption, of the CPCFA's Pollution Control Revenue Bonds, 1992 Series A and B and 1993 Series A and B, or collectively the Old Bonds.

On June 29, 2004, the Utility entered into four separate loan agreements, each dated as of June 1, 2004, with the CPCFA, which issued \$345 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, 2004 Series A (\$70 million), 2004 Series B (\$90 million), 2004 Series C (\$85 million), and 2004 Series D (\$100 million), or collectively the New Bonds, to refund the Old Bonds. The funds made available from the refund of Old Bonds were used to repay the \$345 million term loan facility. Principal and interest payments on the New Bonds are backed by bond insurance and the Utility's obligations under the new loan agreements are supported by \$345 million of First Mortgage Bonds that are held by the trustee for the New Bonds.

Pollution Control Bond Bridge Facilities

During the Utility's Chapter 11 proceeding, approximately \$454 million in aggregate principal amount of pollution control bonds, which were issued for the Utility's benefit and were credit enhanced with letters of credit were redeemed through draws on the letters of credit. On the Effective Date, the Utility executed bridge loans with new lenders who had purchased the \$454 million reimbursement obligations owed by the Utility to the letter of credit issuers and entered into four separate amended and restated reimbursement agreements with new lenders. These reimbursement agreements include a covenant requiring the Utility to maintain, as of the end of each fiscal quarter ending after the Effective Date, a debt to capitalization ratio of at most 65%. The Utility intends to refinance the \$454 million with long-term tax-exempt bonds or taxable debt. The outstanding balance of \$454 million at December 31, 2004 under the amended and restated reimbursement agreements is due and payable on June 5, 2005. At the Utility's request and at the sole discretion of each lender, each amended and restated reimbursement agreement may be extended for additional periods. On the Effective Date, the Utility supported its obligations under the amended and restated reimbursement agreement with \$454 million of First Mortgage Bonds.

Repayment Schedule

At December 31, 2004, PG&E Corporation's and the Utility's combined aggregate amounts of maturing long-term debt as scheduled are reflected in the table below:

	2005	2006	2007	2008	2009	Thereafter	Total
	(in millions)						
PG&E Corporation	\$ 1	\$ —	\$ —	\$ —	\$ —	\$ 280	\$ 281
Utility							
Long-term debt:							
Average fixed interest rate	—	—	3.50%	—	3.60%	5.78%	5.43%
Fixed rate obligations	\$ —	\$ —	\$ 345	\$ —	\$ 600	\$ 4,683	\$ 5,628
Average fixed interest rate	6.42%	6.44%	6.48%	—	—	—	6.45%
Rate reduction bonds	\$ 290	\$ 290	\$ 290	\$ —	\$ —	\$ —	\$ 870
Variable interest rate as of December 31, 2004	3.33%	2.72%	1.19-1.21%	—	—	—	—
Variable rate obligations	\$ 754	\$ 800	\$ 614	\$ —	\$ —	\$ —	\$ 2,168
Other	\$ 3	\$ 1	\$ —	\$ —	\$ —	\$ —	\$ 4
Total consolidated long-term debt	\$ 1,048	\$ 1,091	\$ 1,249	\$ —	\$ 600	\$ 4,963	\$ 8,951

Credit Facilities and Short-Term Borrowings

The following table summarizes PG&E Corporation's and the Utility's short-term borrowings and outstanding credit facilities at December 31, 2004 and 2003. The Utility's credit facilities and short-term borrowings subject to compromise at December 31, 2003 were paid and cancelled on the Effective Date. At December 31, 2004, PG&E Corporation did not have any outstanding balances on its credit facilities. At December 31, 2004, the Utility had \$300 million in short-term borrowings outstanding under the \$850 million revolving credit facility, or working capital facility and approximately \$285 million of letters of credit outstanding. There were no other outstanding balances on the Utility's

credit facilities at December 31, 2004. PG&E Corporation and the Utility's, including their consolidated subsidiaries, short-term borrowings and other credit facilities consist of the following:

	December 31, 2004		December 31, 2003
	Revolving Credit Limit	Outstanding	Outstanding
		(in millions)	
Short-Term Borrowings:			
PG&E Corporation			
Senior credit facility	\$ 200	\$ —	\$ —
Total credit facilities	\$ 200	\$ —	\$ —
Utility			
Accounts receivable financing	\$ 650	\$ —	\$ —
Working capital facility	\$ 850	\$ 300	\$ —
Total credit facilities	\$ 1,500	\$ 300	\$ —
Credit facilities subject to compromise:			
5-year revolving credit facility		\$ —	\$ 938
Total credit facilities subject to compromise		\$ —	\$ 938
Short-term borrowings subject to compromise:			
Bank borrowings—drawn letters of credit for accelerated pollution control agreement		\$ —	\$ 454
Floating rate notes		—	1,240
Commercial paper		—	873
Total credit facilities and short-term borrowings subject to compromise		\$ —	\$ 3,505
			December 31, 2004
Other Credit Facilities:			
Utility			
Letters of credit ⁽¹⁾ :			
Pollution control bonds reimbursement agreements		\$	620
Working capital facility			285
Total letters of credit		\$	905
First mortgage bonds issued to secure and support various debt and credit facilities ⁽¹⁾ :			
Pollution control loan agreements, variable rates, due 2007		\$	620
Pollution control loan agreements, 5.35%, due 2006			200
Pollution control loan agreements, 3.50%, due 2007			345
Pollution control bond bridge facilities, variable rates, due 2005			454
Working capital facility			850
Total first mortgage bonds issued to secure and support various debt and credit facilities		\$	2,469

(1) Off-balance sheet commitments.

PG&E Corporation

Senior Credit Facility

On December 10, 2004, PG&E Corporation entered into a \$200 million three-year revolving senior unsecured credit facility, or senior credit facility, with a syndicate of lenders. The aggregate facility of \$200 million includes a \$50 million sublimit for the issuance of letters of credit and a \$100 million sublimit for swing line loans. Borrowings under the senior credit facility and letters of credit will be used primarily for working capital and other corporate purposes. The senior credit facility has a term of three years and all outstanding amounts are due and payable on December 10, 2007. PG&E Corporation can, at any time, repay amounts outstanding in whole or in part. At PG&E Corporation's request and at the sole discretion of each lender, the senior credit facility may be extended for additional periods. PG&E Corporation has the right to increase, in one or more requests given no more than once a year, the aggregate facility by up to \$100 million provided certain conditions are met. At December 31, 2004, PG&E Corporation had not undertaken any borrowings or issued any letters of credit under the senior credit facility.

Borrowings under the senior credit facility bear interest based, at PG&E Corporation's election, on a Eurodollar rate or a base rate, plus an applicable margin. The base rate equals the higher of the administrative agent-announced base rate or 0.5% above the federal funds rate. Interest is payable by PG&E Corporation at least quarterly, or earlier for loans with shorter interest periods. In addition, a facility fee based on the aggregate facility and a utilization fee based on the average daily amount outstanding under the senior credit facility are payable by PG&E Corporation quarterly in arrears (the utilization fee is levied during any quarter in which the average daily amount outstanding is in excess of 50% of the aggregate facility). The applicable margin, facility fee and utilization fee fluctuate with the Utility's credit rating. The applicable margin ranges between 0.70% and 1.35% for Eurodollar loans and 0% and 0.5% for base rate loans. The facility fee ranges between 0.175% and 0.4% and the utilization fee ranges between 0.125% and 0.25%.

Amounts outstanding under letter of credit arrangements bear interest at the Eurodollar rate plus applicable margin, as detailed above. Interest, a fronting fee, to be determined between PG&E Corporation and the issuing lender, and normal lender costs of issuing and negotiating letter of credit arrangements are payable quarterly in arrears.

The senior credit facility includes covenants requiring that PG&E Corporation maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% and that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting securities of PG&E Corporation.

Utility

Accounts Receivable Financing

On March 5, 2004, the Utility entered into certain agreements providing for the continuous sale of a portion of the Utility's accounts receivable to PG&E Accounts Receivable Company, LLC, or PG&E ARC, a limited liability company wholly owned by the Utility. In turn, PG&E ARC sells interests in its accounts receivable to commercial paper conduits or banks. PG&E ARC may obtain up to \$650 million of financing under such agreements. The borrowings under this facility bear interest at commercial paper rates and a fixed margin based on the Utility's credit ratings. Interest on the facility is payable monthly. The maximum amount available for borrowing under this facility changes based upon the amount of eligible receivables, concentration of eligible receivables and other factors. The credit facility will terminate on March 5, 2007. The Utility began selling accounts receivables to PG&E ARC on the Effective Date and used the proceeds from the sale of the accounts receivable in connection with this credit facility to pay allowed claims on the Effective Date. On May 7, 2004, PG&E ARC paid off this

credit facility, and on December 31, 2004, there were no amounts drawn on the credit facility. Although PG&E ARC is a wholly owned consolidated subsidiary of the Utility, PG&E ARC is legally separate from the Utility. The assets of PG&E ARC (including the accounts receivable) are not available to creditors of the Utility or PG&E Corporation, and the accounts receivable are not legally assets of the Utility or PG&E Corporation. For the purposes of financial reporting, the credit facility is accounted for as a secured financing.

The accounts receivable facility includes a covenant from the Utility requiring it to maintain, as of the end of each fiscal quarter ending after the Effective Date, a debt to capitalization ratio of at most 65%.

Working Capital Facility

On March 5, 2004, the Utility entered into an \$850 million revolving credit facility, or working capital facility, with a syndicate of banks. Loans under the working capital facility will be used primarily to cover operating expenses and seasonal fluctuations in cash flows. Letters of credit under the working capital facility will be used primarily to provide credit enhancements to counter parties for natural gas and electricity procurement transactions. The working capital facility has a term of three years and all outstanding amounts will be due and payable on March 5, 2007. At the Utility's request and at the sole discretion of each lender, the working capital facility may be extended for additional periods. On the Effective Date, the Utility supported its obligation under the working capital facility with First Mortgage Bonds. At December 31, 2004, there were \$300 million of loans outstanding under the working capital facility, which had a weighted average interest rate of 3.42%. The Utility repaid the \$300 million of loans outstanding on February 11, 2005. The Utility also had approximately \$285 million of letters of credit outstanding at December 31, 2004.

The working capital facility includes covenants requiring:

- Maintenance, as of the end of each fiscal quarter ending after the Effective Date, of a debt to capitalization ratio of at most 65%; and
- Until the lien securing the First Mortgage Bonds is released, a limitation on liens other than those specifically permitted by the indenture for the First Mortgage Bonds. As noted above, after the release of the lien, the First Mortgage Bond indenture then limits the ability of the Utility and its significant subsidiaries to incur secured debt and enter into sale and leaseback transactions.

Cash Collateralized Letter of Credit

On March 2, 2004, the Utility entered into a cash collateralized \$400 million letter of credit facility that was used to issue letters of credit to provide credit support in connection with the Utility's pre-existing and new natural gas procurement activities and related purchases of natural gas transportation services. As discussed above, this credit facility was terminated on the Effective Date, and the outstanding balance of letters of credit was transferred to the \$850 million working capital facility.

NOTE 4: RATE REDUCTION BONDS

In December 1997, PG&E Funding, LLC, a limited liability corporation wholly owned by and consolidated by the Utility, issued \$2.9 billion of rate reduction bonds. The proceeds of the rate reduction bonds were used by PG&E Funding, LLC to purchase from the Utility the right, known as "transition property," to be paid a specified amount from a non-bypassable charge levied on residential and small commercial customers (Fixed Transition Amount, or FTA, charges). FTA charges are authorized by the CPUC under state legislation and will be paid by residential and small commercial

customers until the rate reduction bonds are fully retired. Under the terms of a transition property servicing agreement, FTA charges are collected by the Utility and remitted to PG&E Funding, LLC. As a result of credit rating downgrades in January 2001, on January 8, 2001, the Utility was required to begin remitting these FTA receipts to PG&E Funding, LLC on a daily basis, as opposed to once a month, as had previously been required.

The rate reduction bonds have expected maturity dates ranging from 2005 to 2007, and bear interest at rates ranging from 6.42% to 6.48%. The bonds are secured solely by the transition property and there is no recourse to the Utility or PG&E Corporation.

The total amount of rate reduction bonds principal outstanding was \$870 million at December 31, 2004 and \$1.16 billion at December 31, 2003. The scheduled principal payments on the rate reduction bonds for the years 2005 through 2007 are \$290 million for each year. While PG&E Funding, LLC is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets of PG&E Funding, LLC are not available to creditors of the Utility or PG&E Corporation, and the transition property is not legally an asset of the Utility or PG&E Corporation.

NOTE 5: DISCONTINUED OPERATIONS

Effective July 8, 2003 (the date NEGT filed a voluntary petition for relief under Chapter 11), NEGT and its subsidiaries were no longer consolidated by PG&E Corporation in its Consolidated Financial Statements. Under GAAP, consolidation is generally required for entities owning more than 50% of the outstanding voting stock of an investee, except when control is not held by the majority owner. Legal reorganization and bankruptcy represent conditions that can preclude consolidation in instances where control rests with an entity other than the majority owner. In anticipation of NEGT's Chapter 11 filing, PG&E Corporation's representatives who previously served on the NEGT Board of Directors resigned on July 7, 2003, and were replaced with Board members who were not affiliated with PG&E Corporation. As a result, PG&E Corporation no longer retained significant influence over the ongoing operations of NEGT.

Accordingly, at December 31, 2003, PG&E Corporation's net negative investment in NEGT of approximately \$1.2 billion was reflected as a single amount, under the cost method, within the December 31, 2003 Consolidated Balance Sheet of PG&E Corporation. This negative investment represents the losses of NEGT recognized by PG&E Corporation in excess of its investment in and advances to NEGT.

On October 29, 2004, NEGT's plan of reorganization became effective, at which time NEGT emerged from Chapter 11 and PG&E Corporation's equity ownership in NEGT was cancelled. On the effective date, PG&E Corporation reversed its negative investment in NEGT and also reversed net deferred income tax assets of approximately \$428 million and a charge of approximately \$120 million (\$77 million, after tax), in accumulated other comprehensive income, related to NEGT. The resulting net gain has been offset by the \$30 million payment made by PG&E Corporation to NEGT pursuant to the parties' settlement of certain tax-related litigation and other adjustments to NEGT-related liabilities. A summary of the effect on the quarter and year ended December 31, 2004 earnings from discontinued operations is as follows:

	(in millions)
Investment in NEGT	\$ 1,208
Accumulated other comprehensive income	(120)
Cash paid pursuant to settlement of tax related litigation	(30)
Tax effect	(374)
Gain on disposal of NEGT, net of tax	\$ 684

At December 31, 2004, PG&E Corporation's Consolidated Balance Sheet includes approximately \$138 million in income tax liabilities (including \$86 million in current income taxes payable) and approximately \$25 million of other net liabilities related to NEGT. Until PG&E Corporation reaches final settlement of these obligations, it will continue to disclose fluctuations in these estimated liabilities in discontinued operations. Beginning on the effective date of NEGT's plan of reorganization, PG&E Corporation no longer includes NEGT or its subsidiaries in its consolidated income tax returns.

NEGT Operating Results

Included within earnings from discontinued operations on the Consolidated Statements of Operations of PG&E Corporation are NEGT's operating results, summarized below:

	188 Days ended July 7, 2003	Year ended December 31, 2002
	(in millions)	
Operating revenues ⁽¹⁾	\$ 786	\$ 1,766
Income (Loss) before income taxes ⁽¹⁾	(595)	(4,094)

⁽¹⁾ Amounts shown have been adjusted for intercompany eliminations.

Prior to July 8, 2003, NEGT had accounted for certain of its subsidiaries as discontinued operations. The operating results shown above reflect the operating results of USGen New England, Inc. through July 7, 2003 and the other previously discontinued operations through the respective disposal dates. The 2003 pre-tax loss of NEGT and its subsidiaries includes the following gains and losses on disposal of those subsidiaries: a pre-tax gain of approximately \$19 million on disposal related to the sale of Mountain View Power Partners, LLC in January 2003, an additional pre-tax loss of approximately \$3 million on disposal related to the sale of PG&E Energy Trading, Canada Corporation in the first quarter of 2003, and a pre-tax loss of approximately \$9 million on disposal related to the sale of certain Ohio generating plants and related equipment in the second quarter of 2003. Also included in the 2003 pre-tax loss are impairments, write-offs, and other charges of approximately \$229 million.

The 2002 pre-tax loss of NEGT and its subsidiaries includes the following gains and losses on disposal of subsidiaries: a pre-tax loss of approximately \$25 million on the anticipated disposition of PG&E Energy Trading, Canada Corporation in the fourth quarter 2002, subsequently disposed of in 2003 as described above, and a \$1.1 billion pre-tax loss for USGen New England deemed discontinued operations in the fourth quarter 2002. Also included in the 2002 pre-tax loss of NEGT and its subsidiaries are impairments, write-offs, and other charges of approximately \$2.8 billion.

During the second quarter of 2003, NEGT determined that its historical financial reporting presentation of revenues and expenses related to hedging and certain ISO purchase and sales transactions had not been consistent. Certain types of transactions had been reported on a net basis (whereby revenues had been offset by the related expense item) and other types of transactions had been reported on a gross basis. In order to provide a consistent reporting of its trading and hedging transactions, NEGT adopted a net presentation approach for such transactions. PG&E Corporation believes that this method of presentation is preferable under the circumstances. Adopting this change reduced previously reported revenues and expenses of NEGT by approximately \$843 million for the year ended December 31, 2002. In addition, adjustments were made principally for the effects of transactions that had not previously been eliminated in consolidation by NEGT. Such adjustments decreased previously reported revenues and expenses by approximately \$671 million for the year ended December 31, 2002. These changes did not result in any change in consolidated operating income or net income, in the Consolidated Statements of Operations.

As a result of the adoption of DIG C15 and C16, NEGT recognized net losses in 2002 related to the cumulative effect of a change in accounting principle of \$61 million, after-tax. As a result of the adoption of SFAS No. 143, NEGT recognized net losses in 2003 related to a change in accounting principle of \$5 million, after-tax.

On October 29, 2004, the effective date of NEGT's plan of reorganization, amounts due as a result of NEGT affiliates' defaults on numerous agreements were determined and resolved. PG&E Corporation is not a party to these agreements, nor does it anticipate any obligation related to these agreements.

NOTE 6: COMMON STOCK

PG&E Corporation

PG&E Corporation has authorized 800 million shares of no-par common stock of which 418,616,141 shares were issued and outstanding at December 31, 2004 and 416,520,282 were issued and outstanding at December 31, 2003. A wholly owned subsidiary of PG&E Corporation, Elm Power Corporation, holds 24,665,500 shares of the outstanding shares.

During the fourth quarter of 2004, 1,863,600 shares of PG&E Corporation common stock were repurchased through transactions with brokers and dealers on the New York Stock Exchange and/or the Pacific Exchange for an aggregate purchase price of approximately \$60 million. Of this amount, 850,000 shares were purchased at a cost of approximately \$28 million and are held by Elm Power Corporation.

On December 15, 2004, PG&E Corporation entered into an accelerated share repurchase agreement with Goldman, Sachs & Co., or GS&Co., under which PG&E Corporation repurchased 9,769,600 shares of its outstanding common stock for an aggregate purchase price of approximately \$318 million, at an initial price of \$32.50 per share. The repurchase was funded from available cash on hand. The repurchased shares have been retired as of December 20, 2004. Under this arrangement, PG&E Corporation has an obligation to pay GS&Co. a price adjustment based on the daily volume weighted average market price of PG&E Corporation common stock over the term of the arrangement. The price adjustment can be settled, at PG&E Corporation's option, in cash or in shares of its common stock and is accounted for as equity. The number of shares that PG&E Corporation would issue in settlement of the price adjustment feature is capped at approximately 19.5 million shares. At December 31, 2004, this price adjustment obligation amounted to approximately \$7.4 million. If this obligation were settled in shares at December 31, 2004, PG&E Corporation would have issued approximately 222,000 shares. PG&E Corporation expects the arrangement to terminate on February 22, 2005, and to pay GS&Co. approximately \$14 million to settle its obligations.

On December 15, 2004, the Board of Directors of the Utility authorized the repurchase of up to \$800 million, (which has been increased to \$1.8 billion following the receipt of proceeds from the issuance of ERBs) of the Utility's common stock from PG&E Corporation, with such repurchases to be effective from time to time, but no later than December 31, 2006. It was previously anticipated that the first series of ERBs would be issued as early as January 2005. Based on this expectation, on December 15, 2004, PG&E Corporation's Board of Directors authorized the repurchase of up to \$975 million of its outstanding common stock. On February 16, 2005, this authorization was increased to \$1.05 billion. PG&E Corporation expects to enter into a replacement accelerated share repurchase arrangement by the end of February or early March 2005 to repurchase an aggregate of \$1.05 billion of its outstanding shares. The repurchased shares will be retired at that time.

PG&E Corporation repurchased and retired 6,580 shares of its common stock, at a cost of \$102,274 during the year ended December 31, 2002. There were no stock repurchases during the year ended December 31, 2003.

Of the 418,616,141 shares issued and outstanding at December 31, 2004, 1,601,710 shares are PG&E Corporation restricted stock granted under the PG&E Corporation long-term incentive program. Further, PG&E Corporation issues common stock in connection with employee benefit plans. See Note 10 for further discussion.

PG&E Corporation previously issued warrants to purchase 5,066,931 shares of its common stock at an exercise price of \$0.01 per share to lenders during 2002. During 2004, 4,003,812 shares of PG&E Corporation common stock were issued upon the exercise of the warrants. At December 31, 2004, 347,912 of these warrants were outstanding and exercisable with an expiration date of September 2, 2006.

PG&E Corporation did not declare or pay common or preferred stock dividends in 2004, 2003 or 2002.

Utility

The Utility is authorized to issue 800 million shares of its \$5 par value common stock, of which 321,314,760 shares were issued and outstanding as of December 31, 2004 and 2003. PG&E Holdings, LLC, a wholly owned subsidiary of the Utility, holds 19,481,213 of the outstanding shares. PG&E Corporation and PG&E Holdings, LLC hold all of the Utility's outstanding common stock. Approximately 94% of the outstanding common stock of the Utility that is owned by PG&E Corporation was pledged as security for PG&E Corporation's Senior Secured Notes. On November 15, 2004, PG&E Corporation redeemed these notes in full and the pledge was released.

The Utility may pay common stock dividends and repurchase its common stock provided cumulative preferred dividends on its preferred stock and mandatory preferred sinking fund payments are paid. As further discussed in Note 7, upon emergence from Chapter 11, the Utility paid cumulative preferred dividends as of December 31, 2004 and preferred sinking fund payments related to 2004, 2003, and 2002.

NOTE 7: PREFERRED STOCK

PG&E Corporation has authorized 85 million shares of preferred stock, which may be issued as redeemable or non-redeemable preferred stock. No preferred stock of PG&E Corporation has been issued or is outstanding.

Utility

The Utility has authorized 75 million shares of \$25 par value preferred stock, which may be issued as redeemable or non-redeemable preferred stock.

At December 31, 2004 and 2003, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock. Holders of the Utility's 5.0%, 5.5% and 6.0% series of non-redeemable preferred stock have rights to annual dividends ranging from \$1.25 to \$1.50 per share.

At December 31, 2004 and 2003, the Utility had issued and outstanding 5,973,456 shares of redeemable preferred stock. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2004, annual dividends ranged from \$1.09 to \$1.76 per share and redemption prices ranged from \$25.75 to \$27.25 per share.

At December 31, 2004, the Utility's redeemable preferred stock with mandatory redemption provisions consisted of 2.55 million shares of the 6.57% series and 2.375 million shares of the 6.30% series. These series are redeemable at par value plus accumulated and unpaid dividends through the redemption date. These series of preferred stock are subject to mandatory redemption provisions entitling them to sinking funds providing for the retirement of the stock outstanding.

The redemption requirements for the Utility's redeemable preferred stock with mandatory redemption provisions for the 6.57% series are approximately \$4 million per year from 2002 through 2006, and approximately \$55 million in 2007, and for the 6.30% series, approximately \$3 million per year from 2004 through 2008, and approximately \$47 million in 2009. The Utility's redeemable preferred stock with mandatory redemption provisions may be redeemed early, at the Utility's option, if the Utility pays the specified redemption price plus accumulated and unpaid dividends. In 2004, subsequent to the Utility's emergence from Chapter 11, the Utility redeemed \$15 million of preferred stock with mandatory redemption provisions related to 2004, 2003, and 2002.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Due to the Utility's Chapter 11 proceeding, the Utility's Board of Directors did not declare or pay preferred stock dividends from January 31, 2001 through emergence from Chapter 11. Upon emergence from Chapter 11 on the Effective Date, the Utility paid approximately \$101 million of preferred stock dividends, including approximately \$11 million of interest on these dividends, as of December 31, 2004. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series.

PG&E Corporation and the Utility adopted the requirements of SFAS No. 150 in 2003. As a result, the Utility reclassified approximately \$137 million of preferred stock with mandatory redemption provisions as a noncurrent liability in the Utility's Consolidated Balance Sheets. The reclassification did not have an impact on earnings of PG&E Corporation or the Utility. At December 31, 2004, \$122 million of such preferred stock remained on the Utility's Consolidated Balance Sheet.

NOTE 8: RISK MANAGEMENT ACTIVITIES

As discussed in Note 5, NEGT financial results are no longer consolidated with those of PG&E Corporation following the July 8, 2003 Chapter 11 filing of NEGT. NEGT's financial results through July 7, 2003 are reflected in discontinued operations. Because NEGT financial results are no longer consolidated with those of PG&E Corporation, the only risk management activities currently reported by PG&E Corporation are related to Utility non-trading activities, which are executed on a non-trading basis.

Non-Trading Activities

On the Utility's Consolidated Balance Sheets, price risk management activities are presented at fair value of \$5 million in other current assets and \$11 million in other current liabilities for December 31, 2004 and \$8 million in other current assets for December 31, 2003. The costs of these derivatives are recovered in regulated rates charged to customers and the Utility records the offset to the regulatory accounts.

At December 31, 2004, the Utility had no cash flow hedges associated with interest rate risk. At December 31, 2003, the Utility had cash flow hedges associated with interest rate risk presented at fair value of approximately \$17 million in other current assets and approximately \$3 million in accumulated other comprehensive loss, net of tax. These hedges were associated with non-regulated operations and expired in the first quarter of 2004.

The ineffective portion of changes in amounts of the Utility's cash flow hedges associated with interest rate risk was approximately \$3 million for the year ended December 31, 2004 and approximately \$4 million for the year ended December 31, 2003.

Credit Risk

Credit risk is the risk of loss that PG&E Corporation and the Utility would incur if customers or counterparties failed to perform their contractual obligations.

PG&E Corporation had gross accounts receivable of approximately \$2.2 billion at December 31, 2004 and \$2.5 billion at December 31, 2003. The majority of the accounts receivable are associated with the Utility's residential and small commercial customers. Based upon historical experience and evaluation of then-current factors, allowances for doubtful accounts of approximately \$93 million at December 31, 2004 and \$68 million at December 31, 2003 were recorded against those accounts receivable. In accordance with tariffs, credit risk exposure is limited by requiring deposits from new customers and from those customers whose past payment practices are below standard. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in northern and central California. However, material loss due to non-performance from these customers is not considered likely.

The Utility manages credit risk for its largest customers or counterparties by assigning credit limits based on an evaluation of their financial condition, net worth, credit rating, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored frequently and a detailed credit analysis is performed at least annually.

Credit exposure for the Utility's largest customers and counterparties is calculated daily. If exposure exceeds the established limits, the Utility takes immediate action to reduce the exposure or obtain additional collateral, or both. Further, the Utility relies heavily on master agreements that require security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

The Utility calculates gross credit exposure for each of its wholesale customers and counterparties as the current mark-to-market value of the contract (*i.e.* , the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, before the application of credit collateral. During 2004, the Utility recognized no material losses due to contract defaults or bankruptcies. At December 31, 2004 there were three counterparties that represented greater than 10% of the Utility's net credit exposure. Of these three counterparties, two were investment grade representing a total of approximately 47% of the Utility's net wholesale credit exposure and one was below-investment grade representing approximately 17% of the Utility's net wholesale credit exposure.

The Utility conducts business with wholesale counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. This concentration of counterparties may impact the Utility's overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions. Credit losses experienced as a result of electrical and gas procurement activities are expected to be recoverable from customers and are therefore, not expected to have a material impact on earnings.

The schedule below summarizes the Utility's net credit risk exposure, as well as the Utility's credit risk exposure to its wholesale customers or counterparties with a greater than 10% net credit exposure, at December 31, 2004 and December 31, 2003:

	Gross Credit Exposure Before Credit Collateral ⁽¹⁾	Credit Collateral	Net Credit Exposure ⁽²⁾	Number of Wholesale Customer or Counterparties >10%	Net Exposure to Wholesale Customer or Counterparties >10%
			(in millions)		
December 31, 2004	\$ 105	\$ 7	\$ 98	3	\$ 62
December 31, 2003	165	11	154	3	68

⁽¹⁾ Gross credit exposure equals mark-to-market value, notes receivable and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value, liquidity or credit reserves. The Utility's gross credit exposure includes wholesale activity only. Retail activity and payables are not included. Retail activity at the Utility consists of the accounts receivable from the sale of natural gas and electricity to residential and small commercial customers.

⁽²⁾ Net credit exposure is the gross credit exposure minus credit collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.

The schedule below summarizes the credit quality of the Utility's net credit risk exposure to the Utility's wholesale customers and counterparties at December 31, 2004 and December 31, 2003:

	Net Credit Exposure ⁽²⁾	Percentage of Net Credit Exposure
	(in millions)	
Credit Quality ⁽¹⁾		
December 31, 2004		
Investment grade ⁽³⁾	\$ 79	81%
Non-investment grade	19	19%
Total	\$ 98	100%
December 31, 2003		
Investment grade ⁽³⁾	\$ 108	70%
Non-investment grade	46	30%
Total	\$ 154	100%

⁽¹⁾ Credit ratings are determined by using publicly available information. If provided a guarantee by a higher rated entity (e.g., an affiliate), the rating is determined based on the rating of the guarantor.

⁽²⁾ Net credit exposure is the gross credit exposure minus credit collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.

⁽³⁾ Investment grade is determined using publicly available information, i.e., rated at least Baa3 by Moody's and BBB- by S&P. The Utility has assessed certain governmental authorities that are not rated through publicly available information as investment grade based upon an internal assessment of credit worthiness.

NOTE 9: NUCLEAR DECOMMISSIONING

Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear power facilities consist of two units at the Diablo Canyon power plant and the retired facility at Humboldt Bay Unit 3. For ratemaking purposes, the eventual decommissioning of Diablo Canyon Unit 1 is scheduled to begin in 2021 and to be completed in 2040. Decommissioning of Diablo Canyon Unit 2 is scheduled to begin in 2025 and to be completed in 2041, and decommissioning of Humboldt Bay Unit 3 is scheduled to begin in 2009 and be completed in 2015.

The estimated nuclear decommissioning cost for the Diablo Canyon power plant and Humboldt Bay Unit 3 is approximately \$1.89 billion in 2004 dollars (or approximately \$5.25 billion in future dollars). These estimates are based on a 2002 decommissioning cost study and are prepared in accordance with CPUC requirements and are used in the Utility's Nuclear Decommissioning Costs Triennial Proceeding. The Utility's revenue requirements for nuclear decommissioning costs are recovered from customers through a non-bypassable charge that will continue until those costs are fully recovered. The decommissioning cost estimates are based on the plant location and cost characteristics for the Utility's nuclear plants. Actual decommissioning costs are expected to vary from these estimates because of changes in assumed dates of decommissioning, regulatory requirements, technology, costs of labor, materials and equipment.

The estimated nuclear decommissioning cost described above is used for regulatory purposes. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. However, under GAAP requirements, the decommissioning cost estimate is calculated using a different method. In accordance with SFAS No. 143, the Utility adjusts its nuclear decommissioning obligation to reflect the fair value of decommissioning its nuclear power facilities. The Utility records the Utility's total nuclear decommissioning obligation as an asset retirement obligation on the Utility's Consolidated Balance Sheet. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately \$1.2 billion at December 31, 2004 and \$1.1 billion at December 31, 2003. The primary difference between the Utility's estimated nuclear decommissioning obligation as recorded in accordance with GAAP and the estimate prepared in accordance with the CPUC requirements is that GAAP incorporates various potential settlement dates for the obligation and includes an estimated amount for third party labor costs into the fair value calculation.

The Utility has three decommissioning trusts for its Diablo Canyon and Humboldt Bay Unit 3 nuclear facilities. The Utility has elected that two of these trusts be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, the Utility is allowed a deduction for the payments made to the qualified trusts. These payments cannot exceed the amount collected from customers through the decommissioning charge. The qualified trusts are subject to a lower tax rate on income and capital gains, thereby increasing the trusts' after-tax returns. Among other requirements, to maintain the qualified trust status the IRS must approve the amount to be contributed to the qualified trusts for any taxable year. The remaining non-qualified trust is exclusively for decommissioning Humboldt Bay Unit 3. The Utility cannot deduct amounts contributed to the non-qualified trust until such decommissioning costs are actually incurred.

In October 2003, the CPUC issued a decision in the 2002 Nuclear Decommissioning Costs Triennial Proceeding (covering 2003 through 2005) finding that the funds in the Diablo Canyon nuclear decommissioning trusts are sufficient to pay for the Diablo Canyon power plant's eventual decommissioning. In 2004, the Utility was authorized to collect approximately \$18.4 million in rates and contributed approximately \$18.4 million to the qualified nuclear decommissioning trust for Humboldt Bay Unit 3. For 2005, the Utility is authorized to collect approximately \$18.4 million in rates for decommissioning Humboldt Bay Unit 3. Of this amount, the Utility expects to contribute approximately \$18.4 million to the qualified trusts for Humboldt Bay Unit 3. The Utility received approval from the

IRS to contribute a portion of the collected amount to the qualified trust for Humboldt Bay Unit 3. The Utility has requested the IRS approve a revised ruling for the total amount collected to be contributed to the qualified trust for Humboldt Bay Unit 3. If the IRS does not approve the revised ruling request, the Utility must withdraw contributions it made to the qualified trust for 2004 and 2005 in excess of the current IRS ruling amount and contribute the excess amounts, on an after-tax basis, to the non-qualified trust. The Utility would likely request that the CPUC approve an increase in revenue requirements to make up for the reduced amount contributed to the non-qualified trust due to the reduced rate of return attributable to taxes.

The funds in the decommissioning trusts, along with accumulated earnings, will be used exclusively for decommissioning and dismantling the Utility's nuclear facilities. The trusts maintain substantially all of their investments in debt and equity securities. The CPUC has authorized the qualified trust to invest a maximum of 50% of its funds in publicly traded equity securities, of which up to 20% may be invested in publicly traded non-US equity securities. For the non-qualified trust, no more than 60% may be invested in publicly traded equities. The allocation of the trust funds is monitored monthly. To the extent that market movements cause the asset allocation to move outside these ranges, the investments are rebalanced toward the target allocation.

The Utility estimates after-tax annual earnings, including realized gains and losses, in the qualified trusts to be 6.5% and in the non-qualified trusts to be 5.6%. Annual returns decrease in later years as higher portions of the trusts are dedicated to fixed income investments leading up to and during the entire course of decommissioning activities.

All earnings on the assets held in the trusts, net of authorized disbursements from the trusts and investment management and administrative fees, are reinvested. Amounts may not be released from the decommissioning trusts until authorized by the CPUC. At December 31, 2004, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of approximately \$1.6 billion, based on quoted market prices and net of deferred taxes on unrealized gains.

In general, investment securities are exposed to various risks, such as interest rate, credit and market volatility risks. Due to the level of risk associated with certain investment securities, it is reasonably possible that changes in the market values of investment securities could occur in the near term, and such changes could materially affect the trusts' fair value.

The Utility records unrealized gains and losses on investments held in the trusts in other comprehensive income in accordance with SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." Realized gains and losses are recognized as additions or reductions to trust asset balances. The Utility, however, accounts for its nuclear decommissioning obligations in accordance with SFAS No. 71. Therefore, both realized and unrealized gains and losses are ultimately recorded in regulatory asset or liability accounts.

The following table provides a summary of the fair value, based on quoted market prices, of the investments held in the Utility's nuclear decommissioning trusts:

	Maturity Date	Total Unrealized Gains	Total Unrealized Losses	Estimated Fair Value
		(in millions)		
Year ended December 31, 2004				
U.S. government and agency issues	2005-2033	\$ 47	\$ —	\$ 681
Municipal bonds and other	2005-2034	14	—	181
Equity securities		523	—	880
Total		\$ 584	\$ —	\$ 1,742
Year ended December 31, 2003				
U.S. government and agency issues	2004-2032	\$ 47	\$ —	\$ 586
Municipal bonds and other	2004-2034	11	—	147
Equity securities		409	(1)	790
Total		\$ 467	\$ (1)	\$ 1,523

The cost of debt and equity securities sold is determined by specific identification. The following table provides a summary of the activity for the debt and equity securities:

	Year Ended December 31,		
	2004	2003	2002
	(in millions)		
Proceeds received from sales of securities	\$ 1,821	\$ 1,087	\$ 1,631
Gross realized gains on sales of securities held as available-for-sale	28	27	51
Gross realized losses on sales of securities held as available-for-sale	22	(44)	(91)

Spent Nuclear Fuel Storage Proceedings

Under the Nuclear Waste Policy Act of 1982, the Department of Energy, or the DOE, is responsible for the permanent storage and disposal of spent nuclear fuel. The Utility has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from the Utility's nuclear power facilities. Under the Utility's contract with the DOE, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal would be 2018. At the projected level of operation for Diablo Canyon, the Utility's current facilities are able to store on-site all spent fuel produced through approximately 2007. The NRC granted authorization in March 2004 to build an on-site dry cask storage facility to store spent fuel through approximately 2021 for Unit 1 and to 2024 for Unit 2. However, several intervenors in that proceeding filed an appeal of the NRC's decision with the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit. Oral arguments on that appeal are expected in the first quarter of 2005 with a decision anticipated in the second half of 2005. Construction of the on-site dry cask storage facility is expected to start in the second quarter of 2005 after grading permits are obtained from the County of San Luis Obispo. To provide another storage alternative in the event construction of the dry cask storage facility is delayed, the Utility has also requested that the NRC approve another storage option to install a temporary storage rack in each unit's existing spent fuel storage pool that would increase the on-site storage capability to permit the Utility to operate Unit 1 until 2010 and Unit 2 until 2011. If the Utility is unsuccessful in permitting and constructing the on-site dry cask storage facility, and is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo

Canyon may have to be curtailed or halted as early as 2007 and until such time as additional spent fuel can be safely stored.

NOTE 10: EMPLOYEE COMPENSATION PLANS

PG&E Corporation and its subsidiaries provide non-contributory defined benefit pension plans for certain employees and retirees, referred to collectively as pension benefits. PG&E Corporation and the Utility have elected that certain of the trusts underlying these plans be treated under the Internal Revenue Code as qualified trusts. If certain conditions are met, PG&E Corporation and the Utility are allowed a deduction for payments made to the qualified trusts, subject to certain Internal Revenue Code limitations. PG&E Corporation and its subsidiaries also provide contributory defined benefit medical plans for certain retired employees and their eligible dependents, and non-contributory defined benefit life insurance plans for certain retired employees (referred to collectively as other benefits). The following schedules aggregate all PG&E Corporation's and the Utility's plans. As discussed in Note 5, NEGT financial results are no longer consolidated in those of PG&E Corporation following the July 8, 2003 Chapter 11 filing of NEGT. Accordingly, pension and other benefits information is disclosed below for plans that PG&E Corporation and the Utility sponsor at December 31, 2004. PG&E Corporation and its subsidiaries use a December 31 measurement date for all of their plans.

Benefit Obligations

The following reconciles changes in aggregate projected benefit obligations for pension benefits and changes in the benefit obligation of other benefits during 2004 and 2003:

Pension Benefits

	PG&E Corporation		Utility	
	2004	2003	2004	2003
	(in millions)			
Projected benefit obligation at January 1	\$ 7,516	\$ 6,738	\$ 7,509	\$ 6,732
Service cost for benefits earned	194	170	194	170
Interest cost	482	446	482	445
Plan amendments	28	135	28	135
Actuarial loss	667	338	667	338
Settlement	—	(4)	—	(4)
Benefits and expenses paid	(330)	(307)	(329)	(307)
Projected benefit obligation at December 31	\$ 8,557	\$ 7,516	\$ 8,551	\$ 7,509
Accumulated benefit obligation	\$ 7,638	\$ 6,656	\$ 7,632	\$ 6,650

PG&E Corporation has participants in the Utility's Retirement Plan, Retirement Excess Benefit Plan and the Supplemental Executive Retirement Plan. PG&E Corporation's obligation for its participants in these plans was approximately \$19 million at December 31, 2004 and \$15 million at December 31, 2003, and is recorded as a liability in PG&E Corporation's Balance Sheets.

Other Benefits

	PG&E Corporation		Utility	
	2004	2003	2004	2003
	(in millions)			
Benefit obligation at January 1	\$ 1,444	\$ 1,197	\$ 1,444	\$ 1,197
Service cost for benefits earned	32	29	32	29
Interest cost	85	79	85	79
Actuarial loss	(103)	61	(103)	61
Participants paid benefits	30	33	30	33
Plan amendments	—	124	—	124
Benefits paid	(89)	(79)	(89)	(79)
Benefit obligation at December 31	\$ 1,399	\$ 1,444	\$ 1,399	\$ 1,444

PG&E Corporation has participants in the Utility's Postretirement Medical Plan and Postretirement Life Insurance Plan. PG&E Corporation's obligation for its participants in these plans was approximately \$1 million at December 31, 2004 and \$1 million at December 31, 2003, and is recorded as a liability in PG&E Corporation's Balance Sheets.

Change in Plan Assets

PG&E Corporation and the Utility use publicly quoted market values and independent pricing services depending on the nature of the assets, as reported by the trustee to determine the fair value of the plan assets.

The following reconciles aggregate changes in plan assets during 2004 and 2003:

Pension Benefits

	PG&E Corporation		Utility	
	2004	2003	2004	2003
	(in millions)			
Fair value of plan assets at January 1	\$ 7,129	\$ 6,153	\$ 7,129	\$ 6,153
Actual return on plan assets	787	1,280	787	1,280
Company contributions	27	7	27	7
Settlement	—	(4)	—	(4)
Benefits and expenses paid	(329)	(307)	(329)	(307)
Fair value of plan assets at December 31	\$ 7,614	\$ 7,129	\$ 7,614	\$ 7,129

Other Benefits

	PG&E Corporation		Utility	
	2004	2003	2004	2003
	(in millions)			
Fair value of plan assets at January 1	\$ 955	\$ 749	\$ 955	\$ 749
Actual return on plan assets	108	186	108	186
Company contributions	71	72	71	72
Plan participant contribution	30	33	30	33
Benefits and expenses paid	(95)	(85)	(95)	(85)
Fair value of plan assets at December 31	\$ 1,069	\$ 955	\$ 1,069	\$ 955

Funded Status

The following schedule reconciles the plans' aggregate funded status to the prepaid or accrued benefit cost recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets. The funded status is the difference between the fair value of plan assets and projected benefit obligations.

Pension Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
	2004	2003	2004	2003
	(in millions)			
Fair value of plan assets at December 31	\$ 7,614	\$ 7,129	\$ 7,614	\$ 7,129
Projected benefit obligation at December 31	(8,557)	(7,516)	(8,551)	(7,509)
Funded status plan assets less than projected benefit obligation	(943)	(387)	(937)	(380)
Unrecognized prior service cost	378	405	378	405
Unrecognized net loss	1,148	715	1,148	714
Unrecognized net transition obligation	2	8	2	8
Prepaid (accrued) benefit cost	\$ 585	\$ 741	\$ 591	\$ 747
Prepaid benefit cost	\$ 638	\$ 792	\$ 638	\$ 792
Accrued benefit liability	(53)	(51)	(47)	(45)
Additional minimum liability	—	(7)	—	(7)
Intangible asset	—	—	—	—
Accumulated other comprehensive income	—	7	—	7
Prepaid (accrued) benefit cost	\$ 585	\$ 741	\$ 591	\$ 747

Other Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
	2004	2003	2004	2003
	(in millions)			
Fair value of plan assets at December 31	\$ 1,069	\$ 955	\$ 1,069	\$ 955
Benefit obligation at December 31	(1,399)	(1,444)	(1,399)	(1,444)
Funded status plan assets less than benefit obligation	(330)	(489)	(330)	(489)
Unrecognized prior service cost	110	125	110	125
Unrecognized net loss	1	125	1	125
Unrecognized net transition obligation	205	232	205	232
Prepaid (accrued) benefit cost	\$ (14)	\$ (7)	\$ (14)	\$ (7)
Prepaid benefit cost	\$ —	\$ —	\$ —	\$ —
Accrued benefit liability	(14)	(7)	(14)	(7)
Additional minimum liability	—	—	—	—
Prepaid (accrued) benefit cost	\$ (14)	\$ (7)	\$ (14)	\$ (7)

The separate prepaid benefit costs and accrued benefit liabilities of PG&E Corporation's pension and other benefit plans were as follows:

	PG&E Corporation		Utility	
	December 31,		December 31,	
	2004	2003	2004	2003
	(in millions)			
Pension Benefits:				
Prepaid benefit cost	\$ 638	\$ 792	\$ 638	\$ 792
Accrued benefit liabilities	(53)	(51)	(47)	(45)
Other Benefits:				
Prepaid benefit cost	\$ —	\$ —	\$ —	\$ —
Accrued benefit liabilities	(14)	(7)	(14)	(7)

The aggregate projected benefit obligation, accumulated benefit obligation and fair value of plan assets for plans in which the fair value of plan assets are less than either the projected benefit obligation or accumulated benefit obligation as of December 31, 2004 and 2003 were as follows:

	Pension Benefits		Other Benefits	
	2004	2003	2004	2003
	(in millions)			
PG&E Corporation:				
Projected benefit obligation	\$ (8,557)	\$ (7,516)	\$ (1,399)	\$ (1,444)
Accumulated benefit obligation	(7,638)	(6,656)	—	—
Fair value of plan assets	7,614	7,129	1,069	955
Utility:				
Projected benefit obligation	\$ (8,551)	\$ (7,509)	\$ (1,399)	\$ (1,444)
Accumulated benefit obligation	(7,632)	(6,650)	—	—
Fair value of plan assets	7,614	7,129	1,069	955

Components of Net Periodic Benefit Cost

Pension Benefits

	PG&E Corporation			Utility		
	December 31,			December 31,		
	2004	2003	2002	2004	2003	2002
	(in millions)					
Service cost for benefits earned	\$ 194	\$ 170	\$ 140	\$ 194	\$ 170	\$ 138
Interest cost	482	446	438	481	445	435
Expected return on Plan's assets	(563)	(507)	(596)	(563)	(507)	(592)
Amortized prior service cost	63	56	59	63	56	59
Amortization of unrecognized loss (gain)	6	46	(3)	6	46	(3)
Settlement loss	—	1	5	—	1	5
Net periodic benefit cost (income)	\$ 182	\$ 212	\$ 43	\$ 181	\$ 211	\$ 42

Other Benefits

	PG&E Corporation			Utility		
	December 31,			December 31,		
	2004	2003	2002	2004	2003	2002
	(in millions)					
Service cost for benefits earned	\$ 32	\$ 29	\$ 25	\$ 32	\$ 29	\$ 24
Interest cost	84	79	77	84	79	76
Expected return on Plan's assets	(76)	(61)	(76)	(76)	(61)	(75)
Amortized prior service cost	38	28	28	38	28	28
Amortization of unrecognized loss	—	1	(4)	—	1	(4)
Net periodic benefit cost (income)	\$ 78	\$ 76	\$ 50	\$ 78	\$ 76	\$ 49

Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic cost. Weighted average, year-end assumptions were used in determining the plans' projected benefit obligations, while prior year-end assumptions are used to compute net benefit cost.

	Pension Benefits			Other Benefits		
	December 31,			December 31,		
	2004	2003	2002	2004	2003	2002
Discount rate	5.80%	6.25%	6.75%	5.80%	6.25%	6.75%
Average rate of future compensation increases	5.00%	5.00%	5.00%	—	—	—
Expected return on plan assets						
Pension Benefits	8.10%	8.10%	8.10%	—	—	—
Other Benefits:						
Defined Benefit—Medical Plan Bargaining	—	—	—	8.50%	8.50%	8.50%
Defined Benefit—Medical Plan Non-Bargaining	—	—	—	7.60%	7.60%	7.20%
Defined Benefit—Life Insurance Plan	—	—	—	8.50%	8.50%	8.10%

The assumed health care cost trend rate for 2005 is approximately 10%, grading down to an ultimate rate in 2009 and beyond of approximately 5.0%. A one-percentage point change in assumed health care cost trend rate would have the following effects:

	One-Percentage Point Increase	One-Percentage Point Decrease
Effect on postretirement benefit obligation	\$ 30	\$ (27)
Effect on service and interest cost	9	(7)

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed income projected returns were based on historical returns for the broad U.S. bond market. Equity returns were based primarily on historical returns of the S&P 500 Index. For the Utility Retirement Plan, the assumed return of 8.1% compares to a ten-year actual return of 9.5%.

The difference between actual and expected return on plan assets is included in net amortization and deferral, and is considered in the determination of future net benefit income (cost). The actual return on plan assets was above the expected return in 2004 and 2003, and below the expected return in 2002.

Under SFAS No. 71, regulatory adjustments have been recorded in the Consolidated Statements of Operations and Consolidated Balance Sheets of the Utility to reflect the difference between Utility pension expense or income for accounting purposes and Utility pension expense or income for ratemaking, which is based on a funding approach. The CPUC has authorized the Utility to recover the costs associated with its other benefits for 1993 and beyond. Recovery is based on the lesser of the amounts collected in rates or the annual contributions on a tax-deductible basis to the appropriate trusts.

Asset Allocations

The asset allocation of PG&E Corporation's and the Utility's pension and other benefit plans at December 31, 2004 and 2003, and target 2005 allocation was as follows:

	Pension Benefits			Other Benefits		
	2005	2004	2003	2005	2004	2003
Equity Securities						
U.S. Equity	40%	43%	42%	51%	51%	50%
Non-U.S. Equity	20%	22%	22%	20%	21%	22%
Debt Securities	40%	35%	36%	29%	28%	28%
Total	100%	100%	100%	100%	100%	100%

Equity securities include a small amount (less than 0.1% of total plan assets) of PG&E Corporation common stock.

The maturity of debt securities at December 31, 2004 and 2003 ranges from zero to 45 years, with a weighted average maturity of approximately 6.32 years.

PG&E Corporation's and the Utility's investment strategy for all plans is to maintain actual asset weightings within 5% of the target asset allocations. Whenever the actual weighting exceeds the target weighting by 5%, the asset holdings are rebalanced.

A benchmark portfolio for each asset class is set based on market capitalization and valuations of equities and the durations and credit quality of debt securities. Investment managers for each asset

class are retained to periodically adjust, or actively manage, the combined portfolio against the benchmark. Active management covers approximately 70% of the U.S. equity, 60% of the non-U.S. equity, and virtually 100% of the debt security portfolios.

Cash Flow Information

Employer Contributions

PG&E Corporation and the Utility expect to contribute approximately \$20 million to its Pension Benefits Plan, to fund voluntary retirement program obligations and approximately \$65 million to its Other Benefits plans in 2005. These contributions would be consistent with PG&E Corporation's and the Utility's funding policy, which is to contribute amounts that are tax deductible, consistent with applicable regulatory decisions and sufficient to meet minimum funding requirements. None of these benefit plans are subject to a minimum funding requirement in 2005.

Benefits Payments

The estimated benefits expected to be paid in each of the next five fiscal years and in aggregate for the five fiscal years thereafter are as follows:

	PG&E Corporation		Utility	
	(in millions)			
Pension				
2005	\$	349	\$	349
2006		369		368
2007		389		389
2008		412		411
2009		437		436
2010-2015		2,584		2,581
Other benefits				
2005	\$	55	\$	55
2006		65		65
2007		76		76
2008		86		86
2009		96		96
2010-2015		651		651

Defined Contribution Pension Plan

PG&E Corporation and its subsidiaries also sponsor defined contribution pension plans. These plans are qualified under applicable sections of the Internal Revenue Code. These plans provide for tax-deferred salary deductions and after-tax employee contributions as well as employer contributions. Employees designate the funds in which their contributions and any employer contributions are invested. Employer contributions include matching of up to 5% of an employee's base compensation and/or basic contributions of up to 5% of an employee's base compensation. Matching employer contributions are automatically invested in PG&E Corporation common stock. Employees may reallocate matching employer contributions and accumulated earnings thereon to another investment fund or funds available to the plan at any time after they have been credited to their account.

Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Operations amounted to:

Year ended December 31,	PG&E Corporation ⁽¹⁾		Utility
	(in millions)		
2004	\$	40	\$ 39
2003		38	37
2002		52	36

⁽¹⁾ Includes NEG-T-related amounts within PG&E Corporation.

Long-Term Incentive Program

PG&E Corporation maintains a long-term incentive program, or LTIP, that permits stock options, restricted stock and other stock-based incentive awards to be granted to non-employee directors, executive officers and other employees of PG&E Corporation and its subsidiaries. Stock options can be granted with or without associated stock appreciation rights and dividend equivalents.

Stock Options

At December 31, 2004, 31,489,783 shares of PG&E Corporation common stock were authorized for award under the LTIP, of which 10,439,785 shares were available for grant.

PG&E Corporation

The weighted average grant date fair values of options granted using the Black-Scholes valuation method were \$8.70 per share in 2004, \$7.27 per share in 2003, and \$6.61 per share in 2002. Significant assumptions used in the Black-Scholes valuation method for shares granted in 2004, 2003, and 2002 were:

	2004	2003	2002
Expected stock price volatility	45.0%	45.0%	30%
Expected annual dividend payment	\$1.20	\$—	\$—
Risk-free interest rate	3.66%	3.46%	4.65%
Expected life	6.5 years	6.5 years	10 years

Stock options issued after January 2003 become exercisable on a cumulative basis at one-fourth each year commencing one year from the date of the grant. Stock options issued before January 2003 become exercisable on a cumulative basis at one-third each year commencing two years from the date of grant. All options expire ten years and one day after the date of grant. Options outstanding at December 31, 2004, had option prices ranging from \$12.50 to \$33.50, and a weighted average remaining contractual life of 5.60 years.

The following table summarizes stock option activity for the years ended December 31:

	2004		2003		2002	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding at January 1	27,416,380	\$ 21.26	31,067,611	\$ 22.22	34,080,405	\$ 22.11
Granted	2,450,400	27.24	3,649,902	14.62	211,712	19.44
Exercised	(8,173,864)	18.39	(3,818,837)	19.15	(332,436)	23.65
Cancelled	(814,358)	21.37	(3,482,296)	25.18	(2,892,070)	20.56
Outstanding at December 31	20,878,558	22.76	27,416,380	21.26	31,067,611	22.22
Exercisable	13,981,720	24.67	16,072,654	25.34	15,487,462	27.05

The following summarizes information for options outstanding and exercisable at December 31, 2004. Of the outstanding options at December 31, 2004:

- 7,665,219 options had exercise prices ranging from \$12.50 to \$16.68 with a weighted average exercise price of \$14.59 and a weighted average remaining contractual life of 7.00 years, of which 3,227,390 shares were exercisable at a weighted average exercise price of \$14.72;
- 5,727,519 options had exercise prices ranging from \$19.45 to \$27.23 with a weighted average exercise price of \$23.41 and a weighted average remaining contractual life of 6.41 years, of which 3,279,960 shares were exercisable at a weighted average exercise price of \$20.84; and
- 7,485,820 options had exercise prices ranging from \$27.75 to \$33.50, with a weighted average exercise price of \$30.64 and a weighted average remaining contractual life of 3.55 years, of which 7,474,370 shares were exercisable at a weighted average exercise price of \$30.64.

In addition, 1,420,000 options were granted on January 3, 2005, at an exercise price of \$33.02, the then-current market price of PG&E Corporation common stock.

Utility

Stock options outstanding to purchase PG&E Corporation common stock held by Utility employees at December 31, 2004 had option prices ranging from \$12.63 to \$33.50, and a weighted average remaining contractual life of 5.81 years. The following table summarizes the stock option activity for the Utility employees for the years ended December 31:

	2004		2003		2002	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding at January 1	13,543,182	\$ 21.01	13,300,300	\$ 22.32	13,601,834	\$ 22.35
Granted ⁽¹⁾	1,903,238	26.05	2,160,425	14.62	—	—
Exercised	(4,146,084)	19.00	(1,310,156)	20.97	(187,935)	23.49
Cancelled	(231,662)	23.40	(607,387)	27.05	(113,599)	23.98
Outstanding at December 31	11,068,674	22.58	13,543,182	21.01	13,300,300	22.32
Exercisable	6,607,089	24.94	7,668,908	25.33	6,314,620	27.72

⁽¹⁾ Includes net stock options related to employee transfers to the Utility.

The following summarizes information for options outstanding and exercisable at December 31, 2004. Of the outstanding options at December 31, 2004:

- 4,300,054 options had exercise prices ranging from \$12.63 to \$16.68, with a weighted average exercise price of \$14.52 and a weighted average remaining contractual life of 7.05 years, of which 1,453,819 options were exercisable at a weighted average exercise price of \$14.60;
- 2,995,314 options had exercise prices ranging from \$19.81 to \$27.23, with a weighted average exercise price of \$24.03 and a weighted average remaining contractual life of 6.99 years, of which 1,387,964 options were exercisable at a weighted average exercise price of \$20.32; and
- 3,773,306 options had exercise prices ranging from \$28.06 to \$33.50, with a weighted average exercise price of \$30.63 and a weighted average remaining contractual life of 3.46 years, of which 3,765,306 options were exercisable at a weighted average exercise price of \$30.63.

In addition, 1,042,550 options were granted to Utility employees on January 3, 2005 at an exercise price of \$33.02, the then-current market price of PG&E Corporation common stock.

Restricted Stock

At December 31, 2004, a total of 2,088,920 shares of restricted PG&E Corporation common stock had been awarded to eligible employees of PG&E Corporation and its subsidiaries, of which 1,351,675 shares were granted to Utility employees. PG&E Corporation granted 498,910 shares of restricted common stock during 2004, of which 342,180 shares were granted to Utility employees. At December 31, 2004, 1,601,710 shares of restricted PG&E Corporation common stock were outstanding, of which 1,056,610 related to Utility employees. The shares were granted with restrictions and are subject to forfeiture unless certain conditions are met.

The restricted shares are held in an escrow account. The shares become available to the employees as the restrictions lapse. For restricted stock granted in 2003, the restrictions on 80% of the shares lapse automatically over a period of four years at the rate of 20% per year. The compensation expense for these shares remains fixed at the value of the stock at grant date. Restrictions on the remaining 20% of the shares will lapse at a rate of 5% per year if PG&E Corporation is in the top quartile of its comparator group as measured by annual total shareholder return for each year ending immediately before each annual lapse date. The compensation expense recognized for these shares is variable, and changes with the common stock's market price. The performance criteria during 2004 was not met. For restricted stock grants awarded in 2004, there were no restricted stock shares containing performance criteria and the restrictions lapse ratably over four years.

Compensation expense associated with all the shares is recognized on a quarterly basis, by amortizing the unearned compensation related to that period. Total compensation expense resulting from the restricted stock issuance reflected on PG&E Corporation's Consolidated Statements of Operations was approximately \$9 million in 2004 and approximately \$7 million in 2003, of which approximately \$6 million in 2004 and approximately \$4 million in 2003 was recognized by the Utility. The total unamortized balance of unearned compensation resulting from the restricted stock issuance reflected on PG&E Corporation's Consolidated Balance Sheets was approximately \$26 million at December 31, 2004 and \$20 million at December 31, 2003. On January 3, 2005 PG&E Corporation awarded 328,340 shares of restricted stock, of which 241,240 shares were granted to Utility employees.

Performance Shares and Performance Units

Starting in 2004, PG&E Corporation awarded 498,910 performance shares, or phantom stock, to certain officers and employees of PG&E Corporation and its subsidiaries of which 342,180 were awarded to Utility employees. The performance shares, subject to the achievement of certain performance targets, vest on the third year anniversary following the date of the grant. The number of

performance shares that were outstanding at December 31, 2004 was 486,010 of which 330,832 were related to Utility employees. The amount of compensation expense recognized in 2004 in connection with the issuance of performance shares was approximately \$3 million, of which \$2 million was recognized by the Utility. On January 3, 2005, PG&E Corporation awarded 328,340 performance shares, of which 241,240 were awarded to Utility employees.

PG&E Corporation has granted performance units to certain officers and employees of PG&E Corporation and its subsidiaries. The performance units, subject to achievement of certain performance targets, vest one-third per year and are settled in cash annually as vesting occurs in each of the three years following the year of grant. As a result of achieving performance criteria, at December 31, 2004, all remaining units vested and PG&E Corporation recognized compensation expense totaling approximately \$5 million in 2004, of which \$2 million related to the Utility. These amounts were paid in January 2005 to the participating individuals.

PG&E Corporation Supplemental Retirement Savings Plan

The supplemental retirement savings plan provides supplemental retirement alternatives to eligible officers and key employees of PG&E Corporation and its subsidiaries by allowing participants to defer portions of their compensation, including salaries and amounts awarded under various incentive awards and to receive supplemental employer-provided retirement benefits. Under the employee-elected deferral component of the plan, eligible employees may defer all or part of their incentive awards, and 5% to 50% of their salary. Under the supplemental employer-provided retirement benefits component of the plan, eligible employees may receive full credit for employer matching and basic contributions, under the respective defined contribution plan, in excess of limitations set out by the Internal Revenue Code. A separate non-qualified account is maintained for each eligible employee to track deferred amounts. The account's value is adjusted in accordance with the performance of the investment options selected by the employee. Each employee's account is adjusted on a quarterly basis and the change in value is recorded as additional compensation expense or income in the Consolidated Financial Statements. Total compensation expense recognized by PG&E Corporation and the Utility in connection with the plan amounted to:

Year ended December 31,	PG&E Corporation	Utility
	(in millions)	
2004	\$ 3	\$ 1
2003	7	1
2002	2	—

Retention Programs

PG&E Corporation implemented various retention programs in 2001. One of these programs granted key personnel of PG&E Corporation and its subsidiaries with lump-sum cash payments. In addition, another program granted units of special senior executive retention grants.

These grants provided certain employees with PG&E Corporation phantom restricted stock units that vested in full on December 31, 2003 upon PG&E Corporation meeting certain performance measures at that date. A total of 3,044,600 phantom stock units were granted under this program. There were no similar grants in 2004. These units were marked to market based on the market price of PG&E Corporation common stock and amortized as a charge to income over a four-year period. As a result of meeting the performance criteria at December 31, 2003, these units fully vested and the remaining compensation expense was recognized in 2003. Total compensation expense recognized in

connection with these retention mechanisms, including cash payments and phantom restricted stock units, amounted to:

Year ended December 31,	PG&E Corporation		Utility	
	(in millions)			
2004	\$	—	\$	—
2003		63		38
2002		12		7

In January 2004, approximately \$84.5 million was paid to participating individuals in the senior executive retention program. There are no payments remaining under either plan.

NOTE 11: INCOME TAXES

The significant components of income tax (benefit) expense for continuing operations were:

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2004	2003	2002	2004	2003	2002
	(in millions)					
Current:						
Federal	\$ 121	\$ 61	\$ 495	\$ 73	\$ 524	\$ 591
State	91	41	218	85	171	247
Deferred:						
Federal	1,877	422	420	2,000	(88)	349
State	384	(49)	15	410	(62)	2
Tax credits, net	(7)	(17)	(11)	(7)	(17)	(11)
Income tax expense	\$ 2,466	\$ 458	\$ 1,137	\$ 2,561	\$ 528	\$ 1,178

The following describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year ended December 31,			
	2004	2003	2004	2003
	(in millions)			
Deferred income tax assets:				
Customer advances for construction	\$ 472	\$ 386	\$ 472	\$ 386
Unamortized investment tax credits	108	110	108	110
Reserve for damages	270	273	270	273
Environmental reserve	194	172	194	172
Discontinued operations	—	605	—	—
Other	151	110	70	252
Total deferred income tax assets	\$ 1,195	\$ 1,656	\$ 1,114	\$ 1,193
Deferred income tax liabilities:				
Regulatory balancing accounts	\$ 2,097	\$ 139	\$ 2,097	\$ 139
Property related basis differences	2,413	2,005	2,413	2,005
Income tax regulatory asset	209	142	209	142
Unamortized loss on reacquired debt	137	110	137	110
Other	264	218	264	217
Total deferred income tax liabilities	5,120	2,614	5,120	2,613
Total net deferred income taxes liabilities	3,925	958	4,006	1,420
Classification of net deferred income taxes liabilities:				
Included in current liabilities	394	102	377	86
Included in noncurrent liabilities	3,531	856	3,629	1,334
Total net deferred income taxes liabilities	\$ 3,925	\$ 958	\$ 4,006	\$ 1,420

The differences between income taxes and amounts calculated by applying the federal legal rate to income before income tax expense for continuing operations were:

	PG&E Corporation			Utility		
	Year Ended December 31,					
	2004	2003	2002	2004	2003	2002
Federal statutory income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase in income tax rate resulting from:						
State income tax (net of federal benefit)	4.6	4.7	5.3	4.7	4.9	5.4
Effect of regulatory treatment of depreciation differences	(0.5)	(2.9)	1.2	(0.4)	(2.5)	1.1
Tax credits, net	(0.2)	(1.7)	(0.5)	(0.2)	(1.5)	(0.5)
Other, net	0.3	1.3	(1.2)	0.2	0.5	(1.7)
Effective tax rate	39.2%	36.4%	39.8%	39.3%	36.4%	39.3%

The IRS has completed its audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns and has assessed additional federal income taxes of approximately \$79 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and currently is discussing these adjustments with the IRS Appeals Office. PG&E Corporation does not expect final resolution of these appeals to have a material impact on its financial position or results of operations.

In the fourth quarter of 2003, PG&E Corporation made an advance payment to the IRS of \$75 million relating to the 1999 and 2000 audit. The IRS completed its audit of PG&E Corporation's 1999 and 2000 consolidated federal income tax returns during the third quarter of 2004. As a result of the completion of this audit, PG&E Corporation received a refund from the IRS of \$14 million in January of 2005.

The IRS is auditing PG&E Corporation's 2001 and 2002 consolidated federal income tax returns. In September 2004, the IRS issued notices of proposed adjustments that propose to disallow \$104 million of synthetic fuel credits claimed on these tax returns. In addition, the IRS has proposed to disallow abandonment losses deducted on the 2002 tax return related to certain NEGT assets. These assets were transferred to NEGT lenders in the third quarter of 2004. In addition, the IRS has challenged other deductions related to NEGT prior to its Chapter 11 filing. PG&E Corporation is disputing the IRS's proposed adjustments and will contest these disallowances if the IRS continues to assert its current position.

PG&E Corporation has accrued \$52 million associated with NEGT related tax liabilities. In addition, PG&E Corporation has accrued a \$41 million liability to cover potential tax obligations relating to non-NEGT issues raised in outstanding tax audits. The Utility has accrued \$62 million to cover potential tax obligations for outstanding tax audits. Considering these reserves, PG&E Corporation does not expect the resolution of these matters to have a material impact on its financial position or result of operations.

All IRS audits of PG&E Corporation's federal income tax returns prior to 1997 have been closed.

Prior to July 8, 2003, the date that NEGT filed for bankruptcy protection, PG&E Corporation recognized federal income tax benefits related to the losses of NEGT and its subsidiaries. However, after July 7, 2003, PG&E Corporation has not recognized additional income tax benefits for financial reporting purposes with respect to the losses of NEGT and its subsidiaries even though it must continue to include NEGT and its subsidiaries in its consolidated income tax returns. As a result of NEGT's plan of reorganization becoming effective on October 29, 2004, PG&E Corporation cancelled its equity interest in NEGT and no longer includes NEGT or its subsidiaries in its consolidated income tax returns. Remaining deferred tax assets related to NEGT or its subsidiaries, were reversed in discontinued operations in the Consolidated Statements of Operations at the time PG&E Corporation's equity interest in NEGT was cancelled. See Note 5 for further discussion.

In 2003, PG&E Corporation increased its valuation allowance due to the uncertainty in realizing certain state deferred tax assets related to NEGT or its subsidiaries. Valuation allowances of approximately \$24 million were recorded in discontinued operations, and approximately \$5 million in accumulated other comprehensive loss for the year ended December 31, 2003. No valuation allowances were recorded during 2004.

At December 31, 2003, PG&E Corporation had \$420 million of California net operating loss, or NOL. The California NOLs were fully utilized in 2004.

NOTE 12: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have substantial financial commitments and contingencies in connection with agreements entered into supporting the Utility's operating activities. PG&E Corporation has no ongoing financial commitments relating to NEGT's current operating activities.

Commitments

PG&E Corporation

PG&E Corporation has previously agreed to accept the assignment of certain Canadian natural gas pipeline firm transportation contracts effective November 1, 2007, through October 31, 2023, the remaining term of the contracts' duration. The firm quantity under the contracts is approximately 50 million cubic feet per day, or MMcf/d, and PG&E Corporation has estimated annual reservation charges will range between approximately \$10 million and \$12 million. During the term of the contracts, the applicable reservation charges will equal the full tariff rates set by regulatory authorities in Canada and the United States, as applicable. PG&E Corporation is unable to predict the utilization of these contracts, which will depend on market prices, customer demand, and approval of cost recovery by the CPUC, among other factors. PG&E Corporation intends to assign these contracts to the Utility.

Utility

Power Purchase Agreements

Qualifying Facility Power Purchase Agreements —The Utility is required by CPUC decisions to purchase energy and capacity from independent power producers that are qualifying facilities under the Public Utility Regulatory Policies Act of 1978, or PURPA. To implement PURPA, the CPUC required California investor-owned electric utilities to enter into long-term power purchase agreements with qualifying facilities and approved the applicable terms, conditions, prices and eligibility requirements. These agreements require the Utility to pay for energy and capacity. Energy payments are based on the qualifying facility's actual electrical output and CPUC-approved energy prices, while capacity payments are based on the qualifying facility's total available capacity and contractual capacity commitment. Capacity payments may be adjusted if the qualifying facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

As of December 31, 2004, the Utility had agreements with 300 qualifying facilities for approximately 4,300 megawatts, or MW, that are in operation. Agreements for approximately 3,950 MW expire at various dates between 2005 and 2028. Qualifying facility power purchase agreements for approximately 350 MW have no specific expiration dates and will terminate only when the owner of the qualifying facility exercises its termination option. The Utility also has power purchase agreements with approximately 50 inoperative qualifying facilities. The total of approximately 4,300 MW consists of approximately 2,600 MW from cogeneration projects, 700 MW from wind projects and 1,000 MW from projects with other fuel sources, including biomass, waste-to-energy, geothermal, solar and hydroelectric.

On January 22, 2004, the CPUC ordered the California investor-owned electric utilities to allow owners of qualifying facilities with certain power purchase agreements expiring before the end of 2005 to extend these contracts for five years with modified pricing terms. As of December 31, 2004, thirteen qualifying facilities had entered into such five-year contract extensions. Qualifying facility power purchase agreements accounted for approximately 23% of the Utility's 2004 electricity sources, approximately 20% of the Utility's 2003 electricity sources, and approximately 25% of the Utility's 2002 electricity sources. No single qualifying facility accounted for more than 5% of the Utility's 2004, 2003 or 2002 electricity sources.

There are proceedings pending at the CPUC that may impact both the amount of payments to qualifying facilities and the number of qualifying facilities holding power purchase agreements with the Utility. The CPUC will address whether certain payments for short-term power deliveries required by the power purchase agreements comply with the pricing requirements of the PURPA. The CPUC is also considering whether to require the California investor-owned electric utilities to enter into new

power purchase agreements with existing qualifying facilities with expiring power purchase agreements and with newly-constructed qualifying facilities. PG&E Corporation and the Utility are unable to estimate the outcome of these proceedings.

In a proceeding pending at the CPUC, the Utility has requested refunds in excess of \$500 million for overpayments from June 2000 through March 2001 that were made to qualifying facilities pursuant to CPUC orders at approved rates. The net after-tax amount of any qualifying facilities refunds, which the Utility actually realizes in cash, claim offsets or other credits, would be credited to customers, either as a reduction to the principal amount of the second series of ERBs anticipated to be issued in November 2005, or if refunds are received after the second series of ERBs is issued, as a credit to the balancing account that tracks recovery of the customer costs and benefits related to the ERBs. PG&E Corporation and the Utility are unable to estimate the outcome of this proceeding.

Irrigation Districts and Water Agencies —The Utility has contracts with various irrigation districts and water agencies to purchase hydroelectric power. Under these contracts, the Utility must make specified semi-annual minimum payments based on the irrigation districts' and water agencies' debt service requirements, regardless if any hydroelectric power is supplied, and variable payments for operation and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2005 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 5% of the Utility's 2004 electricity sources, approximately 5% of the Utility's 2003 electricity sources and approximately 4% of the Utility's 2002 electricity sources.

Other Power Purchase Agreements

Electricity Purchases to Satisfy the Residual Net Open Position —In 2004 the Utility continued buying electricity to meet its residual net open position. During 2004, more than 10,000 Gigawatt hours, or GWh, of energy was bought and sold in the wholesale market to manage the 2004 residual net open position. Most of the Utility's contracts entered into in 2004 had terms of less than one year. In 2004, the Utility both submitted and requested bids in competitive solicitations to meet intermediate and long-term needs and anticipates procuring electricity under contracts with multi-year terms beginning in 2005.

Renewable Energy Requirement —California law requires that, beginning in 2003, each California retail seller of electricity, except for municipal utilities, must increase its purchases of renewable energy (such as biomass, wind, solar and geothermal energy) by at least 1% of its retail sales per year, the annual procurement target, so that the amount of electricity purchased from renewable resources equals at least 20% of its total retail sales by the end of 2017. The Utility was excused from meeting its annual procurement target under the current law in 2003 and 2004 due to its Chapter 11 proceeding. With its exit from Chapter 11, as of January 1, 2005, the Utility is no longer exempt from complying with its annual procurement target. To meet the 20% goal by the end of 2017, the Utility estimates that it will need to purchase 700-800 GWh of electricity from renewable resources each year. During 2003 and 2004, the Utility entered into several new renewable power purchase contracts that will help the Utility meet its goals. The Utility also is conducting negotiations with several renewable energy providers pursuant to a request for offers made by the Utility in July 2004 that should result in the Utility entering into a number of new renewable contracts in 2005. In January 2005, the California Senate introduced a bill proposing to require the goal to be met by the end of 2010 instead of 2017. The CPUC also has suggested that the 20% goal be met by 2010. The Utility estimates that the accelerated goal would require the Utility to increase the amount of its annual renewable energy purchases to approximately 800-900 GWh. Based on the medium load scenario in the Utility's long-term electricity procurement plan, the Utility believes that it can meet the accelerated goal.

Annual Receipts and Payments —The payments made under qualifying facility, irrigation district, water agency and bilateral agreements during 2002 through 2004 were as follows:

	2004	2003	2002
Qualifying facility energy payments (in millions)	\$ 1,002	\$ 994	\$ 1,051
Qualifying facility capacity payments (in millions)	\$ 487	\$ 499	\$ 506
Irrigation district and water agency payments (in millions)	\$ 61	\$ 62	\$ 57
Other power purchase agreement payments (in millions)	\$ 834	\$ 513	\$ 196

At December 31, 2004, the undiscounted future expected power purchase agreement payments were as follows:

	Qualifying Facility		Irrigation District & Water Agency		Other		Total
			Operations & Maintenance	Debt Service	Energy	Capacity	
	Energy	Capacity					
(in millions)							
2005	\$ 1,060	\$ 506	\$ 51	\$ 26	\$ 53	\$ 41	\$ 1,737
2006	1,082	506	31	26	39	36	1,720
2007	1,070	486	30	26	29	36	1,677
2008	1,040	476	33	26	15	9	1,599
2009	947	436	31	24	10	5	1,453
Thereafter	7,633	3,491	152	117	18	4	11,415
Total	\$ 12,832	\$ 5,901	\$ 328	\$ 245	\$ 164	\$ 131	\$ 19,601

Natural Gas Supply and Transportation Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers. The contract lengths and natural gas sources of the Utility's portfolio of natural gas procurement contracts has fluctuated, generally based on market conditions.

During the period that the Utility was in Chapter 11, the Utility used several different credit arrangements to purchase natural gas, including a \$10 million cash collateralized standby letter of credit and a pledge of its core natural gas customer accounts receivable. In connection with its emergence from Chapter 11, the Utility received investment grade issuer credit ratings from Moody's and S&P. As a result of these credit rating upgrades, the Utility has obtained unsecured credit lines from the majority of its gas supply counterparties.

At December 31, 2004, the Utility's obligations for natural gas purchases and gas transportation services were as follows:

	(in millions)
2005	\$ 829
2006	124
2007	7
2008	—
2009	—
Thereafter	—
Total	\$ 960

Payments for natural gas purchases and gas transportation services amounted to approximately \$1.8 billion in 2004, \$1.5 billion in 2003, and \$898 million in 2002.

Nuclear Fuel Agreements

The Utility has purchase agreements for nuclear fuel. These agreements have terms ranging from two to eight years and are intended to ensure long-term fuel supply. Deliveries under 9 of the 11 contracts in place at the end of 2003 were completed by 2004. New contracts for deliveries in 2005 to 2012 are under negotiation. In most cases, the Utility's nuclear fuel contracts are requirements-based. The Utility relies on large, well-established international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms also are diversified, ranging from fixed prices to market-based prices to base prices that are escalated using published indices.

At December 31, 2004, the undiscounted obligations under nuclear fuel agreements were as follows:

	(in millions)
2005	\$ 46
2006	54
2007	55
2008	50
2009	32
Thereafter	53
Total	<u>\$ 290</u>

Payments for nuclear fuel amounted to approximately \$119 million in 2004, \$57 million in 2003 and \$70 million in 2002.

Reliability Must Run Agreements

The ISO has entered into reliability must run, or RMR, agreements with various power plant owners, including the Utility, that require designated units in certain power plants, known as RMR plants, to remain available to generate electricity upon the ISO's demand when needed for local transmission system reliability. At December 31, 2004, as a party to the Transmission Control Agreement, or the TCA, the Utility estimated that it could be obligated to pay the ISO approximately \$570 million in costs incurred under these RMR agreements during the period January 1, 2005 to December 31, 2006. Of this amount, the Utility estimates that it would receive approximately \$42 million under its RMR agreements during the same period. These costs and revenues are subject to applicable ratemaking mechanisms.

In June 2000, a FERC administrative law judge, or ALJ, issued an initial decision addressing subsidiaries of Mirant Corporation. The decision approved rates and a ratemaking methodology that, if affirmed by the FERC, will require the Mirant subsidiaries that are parties to three RMR agreements with the ISO to refund to the ISO, and the ISO to refund to the Utility, excess payments of approximately \$360 million, including interest, for the availability of Mirant's RMR plants under these agreements. On July 14, 2003, Mirant filed a petition for reorganization under Chapter 11 and on December 15, 2003, the Utility filed claims in Mirant's Chapter 11 proceeding including a claim for an RMR refund. On January 14, 2005, the Utility entered into a settlement with Mirant and its subsidiaries that own RMR units that will resolve the Utility's claim. The settlement agreement is subject to approval by the FERC, the bankruptcy court overseeing the Chapter 11 cases filed by Mirant and these subsidiaries, and to the extent deemed necessary by the Utility, by the bankruptcy court that retains jurisdiction over the Utility's Chapter 11 case. Under the settlement, Mirant will transfer to the Utility Mirant's interest in and equipment for the partially built Contra Costa Unit 8 power plant. If Contra Costa Unit 8 is not transferred to the Utility as a result of various contingencies described in the settlement, Mirant will pay the Utility at least \$70 million in lieu of the plant assets. In addition, under the settlement, the Utility will enter into a contract that gives the Utility the right to dispatch

power from certain RMR units owned by Mirant subsidiaries from 2006-2012, and the Utility will receive approximately \$60 million of allowed claims, credits, offsets, or cash from Mirant or its subsidiaries. The Utility is unable to predict whether and when the FERC or the bankruptcy courts will approve the settlement. Although the settlement resolves issues concerning any refund that might be owed by Mirant, it does not address the underlying merits of the RMR case, which will still be decided by the FERC.

In November 2001, after the ALJ issued the initial decision in Mirant's rate case, two complaints were filed at the FERC against other RMR plant owners, including the Utility, alleging that the ratemaking methodology approved in the ALJ's initial decision should be applied to the other RMR agreements. The complainants asked the FERC to take no action until after the FERC issues its final decision in Mirant's rate case. If the FERC adopts the ALJ's decision in the Mirant rate case and applies the ratemaking methodology to the Utility's RMR plants, the Utility could be required to refund payments it received from the ISO for the availability of the Utility's RMR plants. The Utility has responded to the complaint asserting that the methodology approved in the ALJ's decision should not apply to the Utility. The FERC has not yet acted on these complaints. On December 23, 2004, the Utility filed a settlement with all the complainants that, if approved by FERC, will result in the withdrawal of the complaint with no decision by the FERC on its merits. If the case is not dismissed, the Utility believes the ultimate outcome of this matter will not have an adverse material effect on the Utility's results of operations or financial condition.

Other Commitments and Operating Leases

The Utility has other commitments relating to operating leases, capital infusion agreements, equipment replacements, the self-generation incentive program exchange agreements and telecommunication contracts. At December 31, 2004, the future minimum payments related to other commitments were as follows:

	(in millions)
2005	\$ 123
2006	31
2007	17
2008	14
2009	6
Thereafter	14
Total	<u>\$ 205</u>

Payments for other commitments amounted to approximately \$111 million in 2004, \$74 million in 2003, and \$34 million in 2002.

Contingencies

PG&E Corporation

PG&E Corporation retains a guarantee related to certain NEGТ indemnity obligations issued to the purchaser of an NEGТ subsidiary company during 2000, up to \$150 million. The underlying indemnity obligations of NEGТ have expired and PG&E Corporation's sole remaining exposure relates to the potential of environmental obligations that were known to NEGТ at the time of the sale but not disclosed to the purchaser. PG&E Corporation has never received any claims nor does it consider it probable any claims will occur under the guarantee. Accordingly, PG&E Corporation has made no provision for this guarantee at December 31, 2004.

Utility

PX Block-Forward Contracts

The Utility had PX block-forward contracts, which were seized by California's then-Governor Gray Davis in February 2001 for the benefit of the state, acting under California's Emergency Services Act. The block-forward contracts had an estimated unrealized gain of up to \$243 million at the time the state of California seized them. The Utility, the PX, and some of the PX market participants have filed claims in state court against the state of California to recover the value of the seized contracts; the state of California disputes the plaintiffs' rights to recover and valuations. The estimated value of the seized contracts has been fully reserved in the Utility's financial statements. This state court litigation is pending.

California Energy Crisis Proceedings

FERC Proceedings

Various entities, including the Utility and the state of California are seeking up to \$8.9 billion in refunds for electricity overcharges on behalf of California electricity purchasers for the period May 2000 to June 2001 through a proceeding pending at the FERC. This proceeding, the Refund Proceeding, commenced on August 2, 2000 when a complaint was filed against all suppliers in the ISO and PX markets. On July 25, 2001, the FERC held that refunds would be available for certain overcharges, and established a process to determine the refunds but asserted that it could not order market-wide refunds for periods before October 2, 2000. In December 2002, a FERC ALJ issued an initial decision in the Refund Proceeding finding that power suppliers overcharged the utilities, the state of California and other buyers approximately \$1.8 billion from October 2, 2000 to June 20, 2001, but that California buyers still owe the power suppliers approximately \$3.0 billion, leaving approximately \$1.2 billion in net unpaid bills.

In March 2003, the FERC confirmed most of the ALJ's findings in the Refund Proceeding, but partially modified the refund methodology to include use of a new natural gas price methodology as the basis for mitigated prices. The FERC indicated that it would consider later allowances claimed by sellers for natural gas costs above the natural gas prices in the refund methodology. The FERC directed the ISO and the PX (which operates solely to reconcile remaining refund amounts owed) to make compliance filings establishing refund amounts. The ISO has indicated that it plans to make its compliance filing during the first half of 2005 with the PX to follow. In October 2003, the FERC affirmed its March 2003 decision and various parties appealed to the Ninth Circuit. Briefs have been submitted concerning which power suppliers are subject to refunds, the appropriate time period for which refunds can be ordered, and which transactions are subject to refunds. These matters will be argued before the Ninth Circuit on April 12 and 13, 2005, and a decision is expected in the following months.

The final refunds will not be determined until the FERC issues a final decision in the Refund Proceeding, following the ISO and PX compliance filings and the resolution of the appeals of the FERC's orders. In addition, future refunds could increase or decrease as a result of retroactive adjustments proposed by the ISO, which incorporate revised data provided by the Utility and other entities.

In the FERC's separate proceedings to investigate whether tariff violations occurred in the period before October 2, 2000, the FERC has asserted that it has the power to order power suppliers to disgorge any profits if the FERC finds that the tariffs in force at that time were violated or subject to manipulation. In September 2004, the Ninth Circuit found that the FERC has the authority to provide refunds for tariff violations involving inadequate transaction reporting for sales into the California spot markets throughout the period before October 2, 2000. The FERC has not yet acted on this finding and it is uncertain how it will be applied by the FERC.

The Utility recorded approximately \$1.8 billion of claims filed by various electricity generators in its Chapter 11 proceeding as liabilities subject to compromise. This amount is subject to a pre-petition offset of approximately \$200 million, reducing the net liability recorded to approximately \$1.6 billion. Under a bankruptcy court order, the aggregate allowable amount of ISO, PX and generator claims was limited to approximately \$1.6 billion. The Utility currently estimates that the claims would have been reduced to approximately \$1.0 billion based on the refund methodology recommended in the FERC ALJ's initial decision. The revised methodology adopted by the FERC's March 2003 decision could further reduce the amount by several hundred million dollars, offset by the amount of any additional fuel cost allowance for suppliers.

The Utility has entered into settlements with various power suppliers resolving the Utility's claims against these power suppliers. As discussed in Note 1, as of December 31, 2004, the Utility has recorded offsets to the Settlement Regulatory Asset of approximately \$309 million, pre-tax (\$183 million, after-tax) in connection with settlements. The final net after-tax amount of any amounts received by the Utility under future settlements with energy suppliers will be credited to customers, either as a reduction to the principal amount of the second series of ERBs, anticipated to be issued in November 2005, or if refunds are received after the second series of ERBs is issued, as a credit to the balancing account that tracks recovery of the customer costs and benefits related to the ERBs.

As discussed in Note 13 below, in January 2005, the Utility and other parties entered into a settlement agreement with Mirant Corporation and its subsidiaries, to resolve Mirant's liability for FERC refunds, penalties and civil liabilities arising out of the California energy crisis. The settlement agreement is subject to approval by the FERC, the bankruptcy court overseeing Mirant's bankruptcy proceedings, and to the extent deemed necessary by the Utility, the bankruptcy court that retains jurisdiction over the Utility's Chapter 11 case. Although settlement discussions with a number of other major sellers and other market participants are continuing, the Utility cannot predict whether these settlement negotiations will be successful.

Nuclear Insurance

The Utility has several types of nuclear insurance for Diablo Canyon and Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited, or NEIL. NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to \$3.24 billion per incident. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged outage, the Utility may be required to pay an additional premium of up to \$42.5 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. If one or more acts of domestic terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member within a 12-month period, the maximum recovery under all those nuclear insurance policies may not exceed \$3.24 billion plus the additional amounts recovered by NEIL for these losses from reinsurance. Under the Terrorism Risk Insurance Act of 2002, NEIL would be entitled to receive substantial proceeds from reinsurance coverage for an act caused by foreign terrorism. The Terrorism Risk Insurance Act of 2002 expires on December 31, 2005.

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to \$10.8 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of \$300 million for Diablo Canyon. The balance of the \$10.8 billion of liability protection is covered by a loss-sharing program (secondary financial protection) among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of nuclear reactors that are licensed to operate, designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs

in excess of \$300 million, then the Utility may be responsible for up to \$100.6 million per reactor, with payments in each year limited to a maximum of \$10 million per incident until the Utility has fully paid its share of the liability. Since Diablo Canyon has two nuclear reactors each with a rated capacity of over 100 MW, the Utility may be assessed up to \$201.2 million per incident, with payments in each year limited to a maximum of \$20 million per incident. Although the Price-Anderson Act expired on December 31, 2003, coverage continues to be provided to all licensees, including Diablo Canyon, which had coverage before December 31, 2003. Congress may address renewal of the Price-Anderson Act in future energy legislation.

In addition, the Utility has \$53.3 million of liability insurance for the retired nuclear generating unit at Humboldt Bay power plant and has a \$500 million indemnification from the NRC, for public liability arising from nuclear incidents covering liabilities in excess of the \$53.3 million of liability insurance.

Workers' Compensation Security

The Utility is self-insured for workers' compensation. To maintain its status as a self-insurer for workers' compensation, the Utility must either deposit collateral with the California Department of Industrial Relations, or the DIR, or participate in the Alternative Security Deposit program, or the ASP, which is administered by the Self-Insurer's Security Fund, or the SISF. The ASP is a program that allows the SISF to arrange a composite deposit for participating self-insurers on a portfolio basis, rather than individual self-insurers arranging their deposits individually. The SISF arranges portfolio security to be delivered to the DIR for the aggregate self-insured workers' compensation liabilities for participating self-insurers. The SISF composite deposit for participating self-insurers, including the Utility, was established on July 1, 2004, and resulted in the release of the \$348 million collateral (\$305 million in surety bonds and \$43 million in cash) that existed at June 30, 2004. As a result, PG&E Corporation's guarantee of the Utility's reimbursement obligation associated with these surety bonds was reduced by \$305 million, and the remaining liability is expected to be immaterial.

PG&E Corporation's guarantee of the Utility's underlying obligation to pay workers' compensation claims remains in place. As of December 31, 2004, the actuarially determined workers' compensation liability was approximately \$226 million.

DWR Contracts

The DWR provided approximately 25% of the electricity delivered to the Utility's customers for the year ended December 31, 2004. The DWR purchased the electricity under contracts with various generators. The Utility is responsible for administration and dispatch of the DWR's electricity procurement contracts allocated to the Utility for purposes of meeting a portion of the Utility's net open position, which is the portion of the demand of a utility's customers, plus applicable reserve margins, not satisfied from that utility's own generation facilities and existing electricity contracts. The DWR remains legally and financially responsible for the electricity procurement contracts.

The current DWR contracts terminate at various times through 2012, and consist of must-take and capacity charge contracts. Under must-take contracts, the DWR must take and pay for electricity generated by the applicable generating facility regardless of whether the electricity is needed. Under capacity charge contracts, the DWR must pay a capacity charge but is not required to purchase electricity unless that electricity is dispatched and delivered. In the Utility's proposed long-term integrated energy resource plan filed with the CPUC in July 2004 and approved in December 2004, the Utility has not assumed that the electricity provided under DWR contracts will be renewed beyond their current expiration dates.

The DWR has stated publicly that it intends to transfer full legal title to, and responsibility for, the DWR power purchase contracts to the California investor-owned electric utilities as soon as possible.

However, the DWR power purchase contracts cannot be transferred to the Utility without the consent of the CPUC. The Settlement Agreement provides that the CPUC will not require the Utility to accept an assignment of, or to assume legal or financial responsibility for, the DWR power purchase contracts unless each of the following conditions has been met:

- After assumption, the Utility's issuer rating by Moody's will be no less than A2 and the Utility's long-term issuer credit rating by S&P will be no less than A;
- The CPUC first makes a finding that the DWR power purchase contracts to be assumed are just and reasonable; and
- The CPUC has acted to ensure that the Utility will receive full and timely recovery in its retail electricity rates of all costs associated with the DWR power purchase contracts to be assumed without further review.

Environmental Matters

The Utility may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under the Comprehensive Environmental Response Compensation and Liability Act of 1980, or CERCLA, as amended, and similar state environmental laws. These sites include former manufactured gas plant sites, power plant sites, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if the Utility did not deposit those substances on the site.

The cost of environmental remediation is difficult to estimate. The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can estimate a range of reasonably likely clean-up costs. The Utility reviews its remediation liability on a quarterly basis for each site where it may be exposed to remediation responsibilities. The liability is an estimate of costs for site investigations, remediation, operations and maintenance, monitoring and site closure using current technology, enacted laws and regulations, experience gained at similar sites, and an assessment of the probable level of involvement and financial condition of other potentially responsible parties. Unless there is a better estimate within this range of possible costs, the Utility records the costs at the lower end of this range. It is reasonably possible that a change in these estimates may occur in the near term due to uncertainty concerning the Utility's responsibility, the complexity of environmental laws and regulations, and the selection of compliance alternatives. The Utility estimates the upper end of the cost range using reasonably possible outcomes least favorable to the Utility.

The Utility had an undiscounted environmental remediation liability of approximately \$327 million at December 31, 2004, and approximately \$314 million at December 31, 2003. During the year ended December 31, 2004, the liability increased by approximately \$13 million mainly due to reassessment of the estimated cost of remediation and remediation payments. The approximately \$327 million accrued at December 31, 2004, includes approximately \$102 million related to the pre-closing remediation liability associated with divested generation facilities and approximately \$225 million related to remediation costs for those generation facilities that the Utility still owns, gas gathering sites, compressor stations, third-party disposal sites, and manufactured gas plant sites that either are owned by the Utility or are the subject of remediation orders by environmental agencies or claims by the current owners of the former manufactured gas plant sites. Of the approximately \$327 million environmental remediation liability, approximately \$144 million has been included in prior rate setting proceedings and the Utility expects that approximately \$141 million will be allowable for inclusion in future rates. The Utility also recovers its costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers.

The Utility's undiscounted future costs could increase to as much as \$480 million if the other potentially responsible parties are not financially able to contribute to these costs, or if the extent of contamination or necessary remediation is greater than anticipated. The amount of approximately \$480 million does not include an estimate for the cost of remediation at known sites owned or operated in the past by the Utility's predecessor corporations for which the Utility has not been able to determine whether a liability exists.

Legal Matters

In the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. The most significant of these are discussed below. On the Effective Date, the automatic stay of pending litigation was lifted, so that any state court lawsuits pending before the Utility's Chapter 11 filing that had not yet received relief from the stay can proceed.

Chromium Litigation

There are 14 civil suits pending against the Utility in several California state courts in which plaintiffs allege that exposure to chromium at or near the Utility's compressor stations at Hinkley and Kettleman, California, and the area of California near Topock, Arizona, caused personal injuries, wrongful deaths, or other injury and seek related damages. One of these suits also names PG&E Corporation as a defendant. Currently, there are approximately 1,200 plaintiffs in the chromium litigation cases. Approximately 1,260 individuals filed proofs of claims in the Utility's Chapter 11 case, most of whom also are plaintiffs in the chromium litigation cases. Approximately 1,035 of these claimants filed claims requesting an approximate aggregate amount of \$580 million and approximately another 225 claimants filed claims for an "unknown amount." Pursuant to the Utility's plan of reorganization, these claims have passed through the Utility's Chapter 11 proceeding unimpaired.

The Utility is responding to the suits in which it has been served and is asserting affirmative defenses. The Utility will pursue appropriate legal defenses, including statute of limitations, exclusivity of workers' compensation laws, and factual defenses, including lack of exposure to chromium and the inability of chromium to cause certain of the illnesses alleged.

To assist in managing and resolving litigation with this many plaintiffs, the parties agreed to select plaintiffs from three of the cases for a test trial. Plaintiffs' counsel selected ten of these initial trial plaintiffs, defense counsel selected seven of the initial trial plaintiffs, and one plaintiff and two alternates were selected at random. The Utility has filed 14 motions challenging the test trial plaintiffs' lack of admissible scientific evidence that chromium caused the alleged injuries. The court began hearing argument on two of the motions in February 2004. At a hearing on February 14, 2005, the court indicated that it had signed orders denying the first two motions, but the orders have not been delivered to the parties. The court set a trial date of January 9, 2006 for the first eighteen plaintiffs. The other motions will be heard throughout 2005.

The Utility has recorded a \$160 million reserve in its financial statements with respect to the chromium litigation. PG&E Corporation and the Utility believe that, after taking into account the reserves recorded at December 31, 2004, the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or future results of operations.

Recorded Liability for Legal Matters

In accordance with SFAS No. 5, PG&E Corporation and the Utility make a provision for a liability when it is both probable that a liability has been incurred and the amount of the loss can be reasonably estimated. These provisions are reviewed quarterly and adjusted to reflect the impacts of negotiations, settlements and payments, rulings, advice of legal counsel and other information and events pertaining

to a particular case. In assessing such contingencies, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs.

The liability for legal matters is included in PG&E Corporation's and the Utility's other noncurrent liabilities in the Consolidated Balance Sheets, and totaled approximately \$200 million at December 31, 2004 and \$205 million at December 31, 2003. Based on current information, PG&E Corporation and the Utility do not believe that it is probable that losses associated with legal matters that exceed amounts already recognized will be incurred in amounts that would be material to PG&E Corporation's or the Utility's financial position or results of operations.

NOTE 13: SUBSEQUENT EVENTS

Energy Recovery Bonds

In connection with the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the remaining unamortized portion of the Settlement Regulatory Asset and associated federal and state income and franchise taxes, in an aggregate principal amount of up to \$3.0 billion in two separate series up to one year apart, as expeditiously as practicable after the Effective Date using a securitized financing supported by a DRC provided that certain conditions were met. On February 10, 2005, PERF, a limited liability company wholly owned and consolidated by the Utility, issued \$1.9 billion of ERBs. The proceeds of the ERBs were used by PERF to purchase from the Utility the right, known as "recovery property," to be paid a specified amount from a DRC. DRC charges are authorized by the CPUC under state legislation and will be paid by the Utility's electricity customers until the ERBs are fully retired. Under the terms of a recovery property servicing agreement, DRC charges are collected by the Utility and remitted to PERF.

The aggregate principal amount of the first series of ERBs issued is approximately \$1.9 billion. They were issued in five classes, with scheduled maturities ranging from September 25, 2006 to December 25, 2012, and final legal maturities ranging from September 25, 2008 to December 25, 2014. Interest rates on the five classes range from 3.32% for the earliest maturing class to 4.47% for the latest maturing class.

While PERF is a wholly owned consolidated subsidiary of the Utility, PERF is legally separate from the Utility. The assets of PERF (including the recovery property) are not available to creditors of PG&E Corporation or the Utility and the recovery property is not legally an asset of the Utility or PG&E Corporation.

Mirant Settlement

In January 2005, the Utility entered into a settlement agreement with Mirant Corporation and several of its subsidiaries, resolving overcharges and market manipulation claims from the sale of electricity by Mirant's California operations.

The first part of the two-part settlement is between Mirant and several California parties, including the California Attorney General's Office, the DWR, the CPUC, SCE, San Diego Gas & Electric Company, or the California Parties, and the Utility resolving market manipulation claims, including Mirant's liability for FERC refunds, penalties and civil liabilities arising out of the California energy crisis in 2000 to 2001. Under this portion of the agreement, Mirant will provide the California Parties approximately \$320 million in cash equivalents and \$175 million of allowed bankruptcy claims. Of these amounts, the Utility will receive approximately \$130 million in cash equivalents and \$40 million in allowed claims. The final cash value of the allowed claims will not be known until the completion of Mirant's bankruptcy proceeding. The Utility's net after-tax refund amount will benefit its customers through adjustment of future revenue requirements.

The second part of the settlement is between the Utility and Mirant and is designed to settle claims that Mirant overcharged the Utility under Mirant's RMR contracts and other disputes. Under the settlement agreement, Mirant has agreed to transfer to the Utility the equipment, permits and contracts for the construction of Contra Costa Unit 8, a modern 530-megawatt power plant Mirant started to build, but never completed. The Utility plans to file an application with the CPUC to seek authorization to complete and operate Contra Costa Unit 8 under a cost-of-service ratemaking structure. If the Utility and Mirant do not complete the necessary transfer agreement or if the Utility does not receive the necessary approvals, including CPUC authorization, the Utility will be paid at least \$70 million in lieu of transferring the assets. The settlement agreement also includes a contract that would give the Utility the right from 2006 through 2012 to dispatch power from certain RMR units owned by Mirant subsidiaries when the facilities are not needed by the ISO to meet local reliability needs. In addition, the Utility will receive approximately \$60 million of allowed claims, credits, offsets, and/or cash from Mirant Corporation or its subsidiaries and Mirant will withdraw its outstanding claim in the Utility's bankruptcy proceeding of approximately \$20 million. The settlement may also include separate options under which the Utility, under certain circumstances, would have the right to acquire Mirant's existing Contra Costa and Pittsburg power plants.

The settlement agreement is not effective until it is approved by the FERC, the bankruptcy court overseeing Mirant's bankruptcy proceedings and, to the extent deemed necessary by the Utility, the bankruptcy court that retains jurisdiction over the Utility's Chapter 11 case. PG&E Corporation and the Utility are unable to predict whether and when the settlement agreement will be approved.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

	Quarter ended			
	December 31	September 30	June 30	March 31
	(in millions, except per share amounts)			
2004 ⁽¹⁾				
PG&E CORPORATION				
Operating revenues	\$ 2,986	\$ 2,623	\$ 2,749	\$ 2,722
Operating income ⁽²⁾⁽³⁾	584	509	672	5,353
Income from continuing operations	187	228	372	3,033
Net income ⁽⁴⁾	871	228	372	3,033
Earnings per common share from continuing operations, basic	0.45	0.55	0.89	7.36
Earnings per common share from continuing operations, diluted	0.44	0.53	0.88	7.15
Common stock price per share:				
High	34.46	30.40	30.32	29.35
Low	30.32	27.50	25.90	26.47
UTILITY				
Operating revenues	\$ 2,986	\$ 2,623	\$ 2,749	\$ 2,722
Operating income ⁽²⁾⁽³⁾	584	516	682	5,362
Net income	248	248	412	3,074
Income available for common stock	243	244	408	3,066
2003 ⁽¹⁾				
PG&E CORPORATION				
Operating revenues ⁽⁵⁾	\$ 2,538	\$ 3,103	\$ 2,729	\$ 2,065
Operating income	317	1,173	780	73
Income (loss) from continuing operations	37	508	328	(82)
Net income (loss) ⁽⁶⁾	37	510	227	(354)
Earnings (loss) per common share from continuing operations, basic	0.09	1.25	0.81	(0.21)
Earnings (loss) per common share from continuing operations, diluted	0.09	1.22	0.80	(0.21)
Common stock price per share:				
High	27.98	24.00	22.01	15.35
Low	23.43	20.63	13.41	11.69
UTILITY				
Operating revenues ⁽⁵⁾	\$ 2,538	\$ 3,103	\$ 2,730	\$ 2,067
Operating income	340	1,195	755	49
Net income (loss)	62	589	345	(73)
Income (loss) available for common stock	58	583	339	(79)

- (1) The operating results of NEGT through July 7, 2003 have been excluded from continuing operations and reported as discontinued operations for all periods. Effective July 8, 2003, NEGT and its subsidiaries are no longer consolidated by PG&E Corporation in its Consolidated Financial Statements. See Note 5 of the Notes to the Consolidated Financial Statements for further discussion.
- (2) Operating income for first quarter 2004, as part of the implementation of its plan of reorganization, includes the Utility's recognition of a \$2.2 billion, after-tax (\$3.7 billion, pre-tax) Settlement Regulatory Asset and \$0.7 billion, after-tax (\$1.2 billion, pre-tax), for the Utility's retained generation regulatory assets. See Note 2 of the Notes to the Consolidated Financial Statements for further discussion.
- (3) Operating income for the second quarter 2004, includes the net impact of the 2003 GRC decision of approximately \$432 million, pre-tax. As a result the Utility recorded various regulatory assets and liabilities associated with revenue requirement increases, recovery of retained generation assets, and unfunded taxes, depreciation, and decommissioning.
- (4) Net income for the fourth quarter 2004, includes a gain on disposal of NEGT of approximately \$684 million, net of tax. On October 29, 2004, the effective date of NEGT's plan of reorganization, PG&E Corporation's equity ownership in NEGT was cancelled. See Note 5 of the Notes to the Consolidated Financial Statements for further discussion.

- (5) Operating revenues for the fourth quarter 2003, includes the recognition of a regulatory liability of approximately \$125 million for surcharge revenues collected during 2003 that were determined to be probable of refund under applicable accounting principles.
- (6) Net income for the first quarter 2003 includes \$200 million of impairments, write-offs and charges recognized by NEGТ. These impairments have been excluded from continuing operations and are reported as discontinued operations.

Management's Report on Internal Control Over Financial Reporting

Management of PG&E Corporation and Pacific Gas and Electric Company, or the Utility, is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

The Consolidated Financial Statements of PG&E Corporation and the Utility include the accounts of an entity consolidated pursuant to Financial Accounting Standards Board Interpretation No. 46R, or FIN 46R. Management's responsibility for and assessment of the effectiveness of internal control over financial reporting does not extend to this entity because management has been unable to assess the effectiveness of internal control at this entity due to the fact that PG&E Corporation and the Utility do not have the ability to dictate or modify the controls of this entity and do not have the ability, in practice, to assess those controls. PG&E Corporation's and the Utility's Consolidated Balance Sheets include an increase of \$12 million in total assets and total liabilities as a result of the consolidation of a low-income housing partnership consolidated under FIN 46R.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2004.

Deloitte & Touche LLP, an independent registered public accounting firm, has audited the Consolidated Financial Statements of PG&E Corporation and the Utility for the three years ended December 31, 2004, appearing in this annual report and has issued an attestation report on management's assessment of internal control over financial reporting, as stated in their report, which is included in this annual report on page 145.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") and of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2004 and 2003, and the related consolidated statements of operations, cash flows and shareholders' equity of the Company and of the Utility for each of the three years in the period ended December 31, 2004. These financial statements are the responsibility of the respective managements of the Company and of the Utility. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the respective consolidated financial position of the Company and of the Utility as of December 31, 2004 and 2003, and the respective results of their consolidated operations and cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 of the Notes to the Consolidated Financial Statements, in March 2004, the Company changed the method of computing earnings per share. During 2003, the Company and the Utility adopted new accounting standards to account for asset retirement obligations and financial instruments with characteristics of both liabilities and equity. During 2002, the Company adopted new accounting standards to account for goodwill and intangible assets, impairment of long-lived assets and certain derivative contracts.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's and the Utility's internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 16, 2005 expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

San Francisco, California
February 16, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Boards of Directors and Shareholders of
PG&E Corporation and Pacific Gas and Electric Company

We have audited management's assessment, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*, that PG&E Corporation and subsidiaries (the "Company") and Pacific Gas and Electric Company and subsidiaries (the "Utility") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. As described in *Management's Report on Internal Control Over Financial Reporting*, management excluded from their assessment the internal control over financial reporting of an entity consolidated pursuant to Financial Accounting Standards Board Interpretation No. 46R which represents total assets and total liabilities of \$12 million as of December 31, 2004. Accordingly, our audits did not include the internal control over financial reporting for this entity. The Company's and the Utility's management is responsible for maintaining effective internal control over financial reporting and for their assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's and the Utility's internal control over financial reporting based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audits included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company and the Utility maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company and the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2004 of the Company and the Utility and our report dated February 16, 2005 expressed an unqualified opinion (and includes an explanatory paragraph relating to accounting changes) on those financial statements and financial statement schedules.

DELOITTE & TOUCHE LLP

San Francisco, California
February 16, 2005

RESPONSIBILITY FOR THE CONSOLIDATED FINANCIAL STATEMENTS

PG&E Corporation and Pacific Gas and Electric Company, or the Utility, management are responsible for the integrity of the accompanying Consolidated Financial Statements. The financial statements have been prepared in accordance with the accounting principles generally accepted in the United States of America. Management considers materiality and uses its best judgment to ensure that such statements reflect fairly the financial position, results of operations, and cash flows of PG&E Corporation and the Utility.

PG&E Corporation and the Utility maintain systems of internal controls supported by formal policies and procedures, which are communicated throughout PG&E Corporation and the Utility. These controls are adequate to provide reasonable assurance that assets are safeguarded from material loss or unauthorized use and that necessary records are produced for the preparation of consolidated financial statements. There are limits inherent in all systems of internal controls, based on recognition that the costs of such systems should not exceed the benefits to be derived. PG&E Corporation and the Utility believe that their systems of internal control provide this appropriate balance. PG&E Corporation management also maintains a staff of internal auditors who evaluate the adequacy of, and assess the adherence to, these controls, policies, and procedures for all of PG&E Corporation, including the Utility.

Both PG&E Corporation's and the Utility's Consolidated Financial Statements included herein have been audited by Deloitte & Touche LLP, PG&E Corporation's independent auditors. The audit includes consideration of internal accounting controls and performance of tests necessary to support an opinion. The auditors' report contains an independent informed judgment as to the fairness, in all material respects, of reported results of operations and financial position.

The Audit Committee of the Board of Directors of PG&E Corporation meets regularly with management, internal auditors, and Deloitte & Touche LLP, jointly and separately, to review internal accounting controls and auditing and financial reporting matters. The internal auditors and Deloitte & Touche LLP have free access to the Audit Committee, which consists of five outside directors. The Audit Committee has reviewed the financial data contained in this report.

PG&E Corporation and the Utility are committed to full compliance with all laws and regulations and to conducting business in accordance with high standards of ethical conduct. Management has taken the steps necessary to ensure that all employees and other agents understand and support this commitment. Guidance for corporate compliance and ethics is provided by an officers' Ethics Committee and by a Legal Compliance and Business Ethics organization. PG&E Corporation and the Utility believe that these efforts provide reasonable assurance that each of their operations is conducted in conformity with applicable laws and with their commitment to ethical conduct.

Exhibit 13

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS
PG&E Corporation CONSOLIDATED STATEMENTS OF OPERATIONS (in millions, except per share amounts)
PG&E Corporation CONSOLIDATED BALANCE SHEETS (in millions)
PG&E Corporation CONSOLIDATED BALANCE SHEETS (in millions, except share amounts)
PG&E Corporation CONSOLIDATED STATEMENTS OF CASH FLOWS (in millions)
PG&E Corporation CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (in millions, except share amounts)
Pacific Gas and Electric Company CONSOLIDATED STATEMENTS OF OPERATIONS (in millions)
Pacific Gas and Electric Company CONSOLIDATED BALANCE SHEETS (in millions)
Pacific Gas and Electric Company CONSOLIDATED BALANCE SHEETS (in millions, except share amounts)
Pacific Gas and Electric Company CONSOLIDATED STATEMENTS OF CASH FLOWS (in millions)
Pacific Gas and Electric Company CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY (in millions, except share amounts)
NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS
QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

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Exhibit 21

Subsidiaries		
Name of Subsidiary	Jurisdiction of Formation	Names under which it does business
Pacific Gas and Electric Company	CA	Pacific Gas and Electric Company PG&E
1		

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[Subsidiaries](#)

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Exhibit 23

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statements No. 333-16255 and 333-121518 on Form S-3 and 333-16253, 333-117930, 333-46772, 333-77149 and 333-73054 on Form S-8 of PG&E Corporation and Registration Statements No. 33-62488, and 333-109994 on Form S-3 of Pacific Gas and Electric Company of our reports dated February 16, 2005, (which reports on the financial statements express an unqualified opinion and include an explanatory paragraph relating to accounting changes), relating to the financial statements and financial statement schedules of PG&E Corporation and Pacific Gas and Electric Company and management's report of the effectiveness of internal control over financial reporting, appearing in and incorporated by reference in this Annual Report on Form 10-K of PG&E Corporation and Pacific Gas and Electric Company for the year ended December 31, 2004.

DELOITTE & TOUCHE LLP

San Francisco, California
February 16, 2005

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Exhibit 24.1

**RESOLUTION OF THE
BOARD OF DIRECTORS OF
PG&E CORPORATION**

February 16, 2005

WHEREAS, the Audit Committee of this Board of Directors has reviewed the audited consolidated financial statements for this corporation for the year ended December 31, 2004, and has recommended to the Board that such financial statements be included in the corporation's Annual Report on Form 10-K for the year ended December 31, 2004, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of BRUCE R. WORTHINGTON, LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES is hereby authorized to sign on behalf of this corporation and as attorneys in fact for the President and Chief Executive Officer, and the Senior Vice President, Chief Financial Officer, and Controller of this corporation the Form 10-K Annual Report for the year ended December 31, 2004, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and all amendments and other filings or documents related thereto to be filed with the Securities and Exchange Commission, and to do any and all acts necessary to satisfy the requirements of the Securities Exchange Act of 1934 and the regulations of the Securities and Exchange Commission adopted thereunder with regard to said Form 10-K Annual Report.

I, LINDA Y.H. CHENG, do hereby certify that I am Vice President and Corporate Secretary of PG&E CORPORATION, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held at the office of said corporation on February 16, 2005; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 16th day of February, 2005.

LINDA Y.H. CHENG

Linda Y.H. Cheng
Vice President and Corporate Secretary
PG&E CORPORATION

C O R P O R A T E

S E A L

**RESOLUTION OF THE
BOARD OF DIRECTORS OF
PACIFIC GAS AND ELECTRIC COMPANY**

February 16, 2005

WHEREAS, the Audit Committee of this Board of Directors has reviewed the audited consolidated financial statements for this company for the year ended December 31, 2004, and has recommended to the Board that such financial statements be included in the company's Annual Report on Form 10-K for the year ended December 31, 2004, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of BRUCE R. WORTHINGTON, LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES is hereby authorized to sign on behalf of this company and as attorneys in fact for the President and Chief Executive Officer, the Senior Vice President—Chief Financial Officer and Treasurer, and the Vice President—Controller of this company the Form 10-K Annual Report for the year ended December 31, 2004, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and all amendments and other filings or documents related thereto to be filed with the Securities and Exchange Commission, and to do any and all acts necessary to satisfy the requirements of the Securities Exchange Act of 1934 and the regulations of the Securities and Exchange Commission adopted thereunder with regard to said Form 10-K Annual Report.

I, LINDA Y.H. CHENG, do hereby certify that I am Vice President and Corporate Secretary of PACIFIC GAS AND ELECTRIC COMPANY, a corporation organized and existing under the laws of the State of California; that the above and foregoing is a full, true, and correct copy of a resolution which was duly adopted by the Board of Directors of said corporation at a meeting of said Board which was duly and regularly called and held on February 16, 2005; and that this resolution has never been amended, revoked, or repealed, but is still in full force and effect.

WITNESS my hand and the seal of said corporation hereunto affixed this 16th day of February, 2005.

LINDA Y.H. CHENG

Linda Y.H. Cheng
Vice President and Corporate Secretary
PACIFIC GAS AND ELECTRIC COMPANY

C O R P O R A T E

S E A L

RESOLUTION OF THE BOARD OF DIRECTORS OF PG&E CORPORATION
RESOLUTION OF THE BOARD OF DIRECTORS OF PACIFIC GAS AND ELECTRIC COMPANY

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POWER OF ATTORNEY

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints BRUCE R. WORTHINGTON, LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Form 10-K Annual Report for the year ended December 31, 2004, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 16th day of February, 2005.

/s/ DAVID R. ANDREWS	/s/ ROBERT D. GLYNN, JR.
David R. Andrews	Robert D. Glynn, Jr.
/s/ LESLIE S. BILLER	/s/ DAVID M. LAWRENCE, MD
Leslie S. Biller	David M. Lawrence, MD
/s/ DAVID A. COULTER	/s/ MARY S. METZ
David A. Coulter	Mary S. Metz
/s/ C. LEE COX	/s/ BARBARA L. RAMBO
C. Lee Cox	Barbara L. Rambo
/s/ PETER A. DARBEE	/s/ BARRY LAWSON WILLIAMS
Peter A. Darbee	Barry Lawson Williams

POWER OF ATTORNEY

PETER A. DARBEE, the undersigned, President and Chief Executive Officer of PG&E Corporation, hereby constitutes and appoints BRUCE R. WORTHINGTON, LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as President and Chief Executive Officer (principal executive officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2004, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 16th day of February, 2005.

/s/ PETER A. DARBEE

Peter A. Darbee

POWER OF ATTORNEY

CHRISTOPHER P. JOHNS, the undersigned, Senior Vice President, Chief Financial Officer, and Controller of PG&E Corporation, hereby constitutes and appoints BRUCE R. WORTHINGTON, LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Senior Vice President, Chief Financial Officer, and Controller (principal financial officer and principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2004, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 16th day of February, 2005.

/s/ CHRISTOPHER P. JOHNS

Christopher P. Johns

POWER OF ATTORNEY

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints BRUCE R. WORTHINGTON, LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Form 10-K Annual Report for the year ended December 31, 2004, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 16th day of February, 2005.

/s/ DAVID R. ANDREWS

David R. Andrews

/s/ DAVID M. LAWRENCE, MD

David M. Lawrence, MD

/s/ LESLIE S. BILLER

Leslie S. Biller

/s/ MARY S. METZ

Mary S. Metz

/s/ DAVID A. COULTER

David A. Coulter

/s/ BARBARA L. RAMBO

Barbara L. Rambo

/s/ C. LEE COX

C. Lee Cox

/s/ GORDON R. SMITH

Gordon R. Smith

/s/ PETER A. DARBEE

Peter A. Darbee

/s/ BARRY LAWSON WILLIAMS

Barry Lawson Williams

/s/ ROBERT D. GLYNN, JR.

Robert D. Glynn, Jr.

POWER OF ATTORNEY

GORDON R. SMITH, the undersigned, President and Chief Executive Officer of Pacific Gas and Electric Company, hereby constitutes and appoints BRUCE R. WORTHINGTON, LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as President and Chief Executive Officer (principal executive officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2004, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 16th day of February, 2005.

/s/ GORDON R. SMITH

Gordon R. Smith

POWER OF ATTORNEY

KENT M. HARVEY, the undersigned, Senior Vice President—Chief Financial Officer and Treasurer of Pacific Gas and Electric Company, hereby constitutes and appoints BRUCE R. WORTHINGTON, LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Senior Vice President—Chief Financial Officer and Treasurer (principal financial officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2004, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 16th day of February, 2005.

/s/ KENT M. HARVEY

Kent M. Harvey

POWER OF ATTORNEY

DINYAR B. MISTRY, the undersigned, Vice President—Controller of Pacific Gas and Electric Company, hereby constitutes and appoints BRUCE R. WORTHINGTON, LINDA Y.H. CHENG, WONDY S. LEE, ERIC MONTIZAMBERT, GARY P. ENCINAS, and KATHLEEN HAYES, and each of them, as his attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his capacity as Vice President—Controller (principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2004, required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, I have signed these presents this 16th day of February, 2005.

/s/ DINYAR B. MISTRY

Dinyar B. Mistry

POWER OF ATTORNEY

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EXHIBIT 31.1

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)**

I, Peter A. Darbee, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2004 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2005

PETER A. DARBEE

Peter A. Darbee
President and Chief Executive Officer

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)**

I, Christopher P. Johns, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2004 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2005

CHRISTOPHER P. JOHNS

Christopher P. Johns
Senior Vice President, Chief Financial Officer and Controller

EXHIBIT 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

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EXHIBIT 31.2

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)**

I, Gordon R. Smith, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2004 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Gordon R. Smith
President and Chief Executive Officer

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)**

I, Kent M. Harvey, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2004 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:
 - a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;
 - b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;
 - c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and
 - d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and
5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):
 - a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
 - b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 18, 2005

KENT M. HARVEY

Kent M. Harvey
Senior Vice President, Chief Financial Officer and Treasurer

[EXHIBIT 31.2](#)

[CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14\(a\)](#)

[CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14\(a\)](#)

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EXHIBIT 32.1

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2004, I, Peter A. Darbee, President and Chief Executive Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2004, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2004, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

PETER A. DARBEE

PETER A. DARBEE
President and Chief Executive Officer

February 18, 2005

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2004, I, Christopher P. Johns, Senior Vice President, Chief Financial Officer and Controller of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2004, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in such Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2004, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

CHRISTOPHER P. JOHNS

CHRISTOPHER P. JOHNS
Senior Vice President,
Chief Financial Officer and Controller

February 18, 2005

EXHIBIT 32.1

[CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350](#)
[CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PURSUANT TO 18 U.S.C. SECTION 1350](#)

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EXHIBIT 32.2

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2004, I, Gordon R. Smith, President and Chief Executive Officer of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) such Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2004, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in such Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2004, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

GORDON R. SMITH

GORDON R. SMITH
President and Chief Executive Officer

February 18, 2005

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2004, I, Kent M. Harvey, Senior Vice President, Chief Financial Officer and Treasurer of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) such Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2004, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in such Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2004, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

KENT M. HARVEY

KENT M. HARVEY

Senior Vice President, Chief Financial Officer and Treasurer

February 18, 2005

[QuickLinks](#)

[EXHIBIT 32.2](#)

[CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350](#)
[CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER PURSUANT TO 18 U.S.C. SECTION 1350](#)

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