

PG&E CORP

FORM 10-K (Annual Report)

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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, 2003

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 Preferred Stock Purchase Rights	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
7.90% Deferrable Interest Subordinated Debentures	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, 2003, the last business day of the second fiscal quarter:

PG&E Corporation Common Stock	\$8,164 million
Pacific Gas and Electric Company Common Stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 17, 2004:

PG&E Corporation:	418,976,121
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, 2003	Part I (Item 1), Part II (Items 5, 6, 7, 7A and 8), Part IV (Item 15)

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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, electricity transmission, and natural gas 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. PG&E Corporation also currently owns National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, Inc., which engages 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 3.9 million natural gas distribution customers at December 31, 2003. The Utility had approximately \$29.1 billion of assets at December 31, 2003, and generated revenues of approximately \$10.4 billion in 2003. 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. The factors that caused the Utility to take this action 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 2003 Annual Report to Shareholders, or the Annual Report, which is incorporated by reference into this report. The Utility has retained control of its assets and is authorized to operate its business as a debtor-in-possession during its Chapter 11 proceeding.

On December 19, 2003, the CPUC, PG&E Corporation and the Utility entered into a settlement agreement, or the Settlement Agreement, that contemplated a plan of reorganization, or the Plan of Reorganization, which fully incorporates the Settlement Agreement. The Plan of Reorganization provides that the Utility will pay allowed creditor claims in full, plus applicable interest, and emerge from Chapter 11 as an investment grade entity. On December 22, 2003, the bankruptcy court confirmed the Plan of Reorganization. The Settlement Agreement and Plan of Reorganization are discussed further below, in the MD&A and in Note 2 of the Notes to the Consolidated Financial Statements in the Annual Report.

NEGT

NEGT was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. NEGT's subsidiaries include: Gas Transmission Northwest Corporation (formerly PG&E Gas Transmission Northwest Corporation), North Baja Pipeline, LLC, National Energy Power Company, LLC (formerly PG&E Generating Power Group, LLC) and its subsidiaries, USGen New England, Inc. and its affiliates, and National Energy & Gas Transmission Trading Holdings Corporation and its subsidiaries.

On July 8, 2003, NEGT filed a voluntary petition for relief under the provisions of Chapter 11 in the U.S. Bankruptcy Court for the District of Maryland, Greenbelt Division. On the same day, each of the following indirect wholly owned subsidiaries of NEGT filed a voluntary petition for relief under Chapter 11: PG&E Energy Trading Holdings Corporation (now NEGT Energy Trading Holdings Corporation), PG&E Energy Trading-Power, L.P. (now NEGT Energy Trading — Power, L.P.), PG&E Energy Trading — Gas Corpora-

tion (now NEGТ Energy Trading — Gas Corporation), and PG&E ET Investments Corporation (now NEGТ ET Investments Corporation) and, separately, USGen New England, Inc. On July 29, 2003, two other subsidiaries, Quantum Ventures and PG&E Energy Services Ventures, Inc. (now Energy Services Ventures, Inc.), each filed voluntary Chapter 11 petitions.

The factors that caused NEGТ and its subsidiaries to take this action are discussed in the MD&A and in Note 5 of the Notes to the Consolidated Financial Statements in the Annual Report. Pursuant to Chapter 11, NEGТ and its subsidiaries that filed Chapter 11 petitions retain control of their assets and are authorized to operate their businesses as debtors-in-possession while they are subject to the jurisdiction of the bankruptcy court.

NEGТ's proposed plan of reorganization, if implemented, would eliminate PG&E Corporation's equity interest in NEGТ and its subsidiaries. In anticipation of NEGТ's Chapter 11 filing, PG&E Corporation's representatives, who previously served as directors of NEGТ resigned on July 7, 2003, and were replaced with directors who are not affiliated with PG&E Corporation. As a result, PG&E Corporation no longer retains significant influence over NEGТ. Accordingly, effective July 8, 2003, NEGТ's results of operations no longer are consolidated with those of PG&E Corporation. NEGТ's results of operations through July 7, 2003, and for prior years have been reclassified as discontinued operations and PG&E Corporation now accounts for its investment in NEGТ using the cost method of accounting.

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 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, 2003, PG&E Corporation and its subsidiaries and affiliates (excluding NEGТ) had approximately 20,600 employees, including approximately 20,300 employees of the Utility. Of the Utility's employees, approximately 13,500 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 International Union of Security Officers/ SEIU, 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.

The Utility's Plan of Reorganization and Settlement Agreement

The Plan of Reorganization provides that the Utility will pay all allowed creditor claims in full (except for the claims of holders of certain pollution control-related bond obligations that will be reinstated) from the proceeds of a public offering of long-term debt, cash on hand, and draws on revolving credit facilities. At December 31, 2003, allowed claims in the Utility's Chapter 11 proceeding amounted to approximately \$12.3 billion.

The Settlement Agreement permits the Utility to emerge from Chapter 11 as an investment grade entity by generally ensuring that the Utility will have the opportunity to collect in rates reasonable costs of providing its utility service. The Settlement Agreement provides that the Utility's authorized return on equity will be no less than 11.22% per year and, except for 2004 and 2005, its authorized equity ratio will be no less than 52% until the Utility's credit rating has increased to a specified level. The Settlement Agreement establishes a

\$2.21 billion after-tax regulatory asset and allows for the recognition of an approximately \$800 million after-tax regulatory asset related to generation assets. The Settlement Agreement and related decisions by the CPUC provide that the Utility's revenue requirement will be collected regardless of sales levels and that the Utility's rates will be adjusted in a timely manner to accommodate changes in costs that the Utility incurs.

On January 20, 2004, several parties filed applications with the CPUC requesting that the CPUC rehear and reconsider its decision approving the Settlement Agreement. Although the CPUC is not required to act on these applications within a specific time period, if the CPUC has not acted on an application within 60 days, that application may be deemed denied for purposes of seeking judicial review. In addition, the two CPUC Commissioners who did not vote to approve the Settlement Agreement and a municipality have appealed the bankruptcy court's confirmation order in the U.S. District Court for the Northern District of California, or the District Court. On January 5, 2004, the bankruptcy court denied a request to stay the implementation of the Plan of Reorganization until the appeals are resolved. The District Court will set a schedule for briefing and argument of the appeals at a later date. No additional parties may request rehearings or make appeals of the CPUC's approval of the Settlement Agreement or the bankruptcy court's confirmation order.

Implementation of the Plan of Reorganization is subject to various conditions, including the consummation of the public offering of long-term debt, the receipt of investment grade credit ratings and final CPUC approval of the Settlement Agreement. For purposes of these conditions, final approval means approval on behalf of the CPUC that is not subject to any pending appeal or further right of appeal, or approval on behalf of the CPUC that, although subject to a pending appeal or further right of appeal, has been agreed by the Utility and PG&E Corporation to constitute final approval. Thus, the terms of the Plan of Reorganization permit the Utility and PG&E Corporation to cause the Plan of Reorganization to become effective (and permit the Utility to issue the long term debt) while the CPUC's approvals are subject to pending appeals or further rights of appeal. Until certain conditions or events regarding the effectiveness of the Plan of Reorganization discussed above are resolved further, PG&E Corporation and the Utility cannot conclude that the applicable accounting probability standard needed to record the regulatory assets contemplated by the Settlement Agreement has been met. PG&E Corporation and the Utility believe that the Utility and the long-term debt to be issued will receive investment grade credit ratings. The Utility has targeted April 2004 to complete the sale of the long-term debt, which the Utility expects to be the last condition of the Plan of Reorganization to be satisfied. The Plan of Reorganization provides that the effective date will occur 11 business days after all the conditions have been satisfied or, with respect to all conditions except those relating to investment grade credit ratings, waived by PG&E Corporation and the Utility. There can be no assurance that the Settlement Agreement will not be overturned on rehearing or appeal or that the Plan of Reorganization will become effective.

The Settlement Agreement and Plan of Reorganization are discussed further in the MD&A and in Note 2 of the Notes to the Consolidated Financial Statements in the Annual Report.

Refinancing Supported by a Dedicated Rate Component

Under the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the remaining unamortized pre-tax balance of the \$2.21 billion after-tax regulatory asset and related federal, state and franchise taxes, up to a total of \$3.0 billion, as expeditiously as practicable after the effective date of the Plan of Reorganization using a securitized financing supported by a dedicated rate component, provided the following conditions are met:

- Authorizing California legislation satisfactory to the CPUC, The Utility Reform Network, or TURN, and the Utility is passed and signed into law allowing securitization of the regulatory asset and associated federal and state income and franchise taxes and providing for the collection in the Utility's rates of any portion of the associated tax amounts not securitized;
- The CPUC determines that, on a net present value basis, the refinancing would save customers money over the term of the securitized debt compared to the regulatory asset;
- The refinancing will not adversely affect the Utility's issuer or debt credit ratings; and

- The Utility obtains, or decides it does not need, a private letter ruling from the Internal Revenue Service, or IRS, confirming that neither the refinancing nor the issuance of the securitized debt is a presently taxable event.

The Utility would be permitted to complete the refinancing in up to two tranches up to one year apart, and would issue sufficient callable debt or debt with earlier maturities as part of the Plan of Reorganization to accommodate the refinancing supported by a dedicated rate component. Upon refinancing with securitization, the equity and debt components of the Utility's rate of return on the regulatory asset would be eliminated. Instead the utility would collect from customers amounts sufficient to service the securitized debt. The Utility would use the securitization proceeds to rebalance its capital structure in order to maintain the capital structure provided for under the Settlement Agreement.

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. These statements are based on current expectations and assumptions which management believes are reasonable and on the information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," "could," "should," "would," "may" and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking statements.

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:

Whether and on What Terms the Plan of Reorganization is Implemented

- The timing and resolution of the pending applications for rehearing of the CPUC's approval of the Settlement Agreement and any appeals that may be filed with respect to the disposition of the rehearing applications;
- The timing and resolution of the pending appeals of the bankruptcy court's confirmation of the Plan of Reorganization;
- Whether the investment grade credit ratings and other conditions required to implement the Plan of Reorganization are obtained or satisfied; and
- Future equity and debt market conditions, future interest rates, and other factors that may affect the Utility's ability to implement the Plan of Reorganization or affect the amounts and terms of the debt proposed to be issued under the Plan of Reorganization.

Operating Environment

- Unanticipated changes in operating expenses or capital expenditures;
- The level and volatility of wholesale electricity and natural gas prices and supplies and the Utility's ability to manage and respond to the levels and volatility successfully;
- 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;

- The extent to which the Utility's residual net open position (*i.e.* , the amount of electricity the Utility needs to meet its customers' electricity demands that is not provided by Utility-owned generation, Utility power purchase contracts, or the electricity provided by the California Department of Water Resources, or DWR, and allocated to the Utility) increases or decreases due to changes in customer and economic growth rates, the periodic expiration or termination of Utility or DWR power purchase contracts, the reallocation of the DWR power purchase contracts, whether various counterparties are able to meet their obligations under their power sale agreements with the Utility or with the DWR; the retirement or other closure of the Utility's electricity generation facilities, the performance of the Utility's electricity generation facilities, and other factors;
- The operation of the Utility's Diablo Canyon nuclear power plant, which exposes the Utility to potentially significant environmental 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 its Diablo Canyon power plant 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 outcome of the Utility's 2003 General Rate Case, or the GRC;
- Prevailing governmental policies and legislative or regulatory actions generally, including those of the California legislature, U.S. Congress, the CPUC, the FERC and the Nuclear Regulatory Commission, or the NRC, with regard to 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;
- 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 California investor-owned electric utilities;
- 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 services by local public utility districts, self-generation by its customers 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 and the extent to which cities, counties and others in the Utility’s service territory begin directly serving the Utility’s customers with their own facilities or combine to form community choice aggregators.

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 120,428 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead). There are 89 transmission substations and 45 transmission switching stations. A transmission substation is a fenced facility where voltage is transformed from one transmission voltage level to another. There are 609 distribution substations and 117 low voltage distribution substations. There are 264 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 1,012 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.

2003 Electricity Deliveries

The following table shows the percentage of the Utility’s total 2003 electricity deliveries represented by each of its major customer classes:

(80,156 GWhs)

Agricultural and Other Customers	6%
Industrial Customers	18%
Residential Customers	36%
Commercial Customers	40%



Electricity Distribution Operating Statistics

The following table shows certain of the Utility's operating statistics from 1999 to 2003 for electricity sold or delivered, including the classification of sales and revenues by type of service.

	2003	2002	2001	2000	1999
Customers (average for the year):					
Residential	4,286,085	4,171,365	4,165,073	4,071,794	4,017,428
Commercial	493,638	483,946	484,430	471,080	474,710
Industrial	1,372	1,249	1,368	1,300	1,151
Agricultural	81,378	78,738	81,375	78,439	85,131
Public street and highway lighting	26,650	24,119	23,913	23,339	20,806
Other electric utilities	4	5	5	8	12
Total	4,889,127	4,759,422	4,756,164	4,645,960	4,599,238
Deliveries (in GWh):(1)					
Residential	29,024	27,435	26,840	28,753	27,739
Commercial	31,889	31,328	30,780	31,761	30,426
Industrial	14,653	14,729	16,001	16,899	16,722
Agricultural	3,909	4,000	4,093	3,818	3,739
Public street and highway lighting	605	674	418	426	437
Other electric utilities	76	64	241	266	167
Subtotal	80,156	78,230	78,373	81,923	79,230
DWR	(23,342)	(21,031)	(28,640)	—	—
Total non-DWR electricity	56,814	57,199	49,733	81,923	79,230
Revenues (in millions):					
Residential	\$ 3,671	\$ 3,646	\$ 3,396	\$ 3,062	\$ 2,975
Commercial	4,440	4,588	4,105	3,110	2,980
Industrial	1,410	1,449	1,554	1,053	1,044
Agricultural	522	520	525	420	404
Public street and highway lighting	69	73	60	43	49
Other electric utilities	24	10	39	26	17
Subtotal	10,136	10,286	9,679	7,714	7,469
DWR	(2,243)	(2,056)	(2,173)	—	—
Direct access credits	(277)	(285)	(461)	(1,055)	(348)
Miscellaneous(2)	(52)	193	244	202	162
Regulatory balancing accounts	18	40	37	(7)	(51)
Total electricity operating revenues	\$ 7,582	\$ 8,178	\$ 7,326	\$ 6,854	\$ 7,232
Other Data:					
Average annual residential usage (kWh)	6,772	6,577	6,444	7,062	6,905
Average billed revenues (cents per KWh):					
Residential	12.65	13.29	12.65	10.65	10.72
Commercial	13.92	14.65	13.34	9.79	9.79
Industrial	9.62	9.84	9.71	6.23	6.24
Agricultural	13.35	13.00	12.83	11.00	10.81
Net plant investment per customer	\$ 2,689	\$ 2,105	\$ 2,018	\$ 1,969	\$ 2,388

(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 2003 represented by each major electricity resource:

Owned generation (nuclear, fossil fuel-fired and hydroelectric facilities)	36%
DWR	29%
Qualifying Facilities/ Renewables	23%
Irrigation Districts	5%
Other Power Purchases	7%

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.

Generation Facilities

At December 31, 2003, 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:			2,174
Diablo Canyon	San Luis Obispo	2	
Hydroelectric:	16 counties in northern and central California	107	2,684
Conventional			
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, 2003, the Utility's Diablo Canyon power plant achieved a capacity factor of approximately 88.5%.

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 19 to 21 months. The average length of a refueling outage over the last five years has been approximately 35 days. It is anticipated, however, that additional work will be required during future scheduled outages leading up to the steam generator replacements in 2008 and 2009 discussed below. This additional work will lengthen the forecasted outage durations to the time periods shown below. The table below shows outages of up to 80 days to accommodate non-routine tasks, such as expanded steam generator inspection and repair, low pressure turbine rotor replacement and the first of two proposed 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.

	2004	2005	2006	2007	2008
Unit 1					
Refueling	March	October	—	April	—
Duration (days)	48	45	—	35	—
Startup	May	November		June	
Unit 2					
Refueling	October		April		February
Duration (days)	42	—	42	—	80
Startup	December	—	May	—	April

During a routine inspection conducted as part of the last refueling of Unit 2 in February 2003, the Utility found indications of steam generator tube cracking in locations and of a size not previously expected. After careful inspection and analysis, Unit 2 was able to safely restart after that outage and the Utility received the approval of the NRC to operate without further steam generator inspection until the next scheduled refueling in the fall of 2004. The Utility, however, is planning to accelerate the replacement of the steam generators in Unit 2 from 2009 to 2008. The Utility plans to replace Unit 1's steam generators in 2009. The capital expenditures necessary to complete these projects are discussed further in the MD&A.

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 additional annual premiums of up to \$36.7 million.

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 \$10.9 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 \$10.9 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 reactors 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 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, that 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 Humboldt Bay Unit 3 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 83 permits and 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 three years, the Utility has received six renewed hydroelectric project licenses from the FERC. Licenses associated with approximately 928 MW expire within the next five years. Licenses associated with approximately 2959 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, or the DWR allocated contracts, to the Utility's customers. Electricity from DWR allocated contracts represented approximately 29% of the Utility's total sources of electricity in 2003. 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. 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 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.

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 will be no less than A2 and the Utility's long-term issuer credit rating by Standard & Poor's 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 Agreements

Qualifying Facility 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. Under PURPA, the CPUC required California investor-owned electric utilities to enter into a series of long-term power purchase agreements with qualifying facilities and approved the applicable terms, conditions, price options 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 facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

As a result of the energy crisis, the Utility owed approximately \$1 billion to qualifying facilities when it filed its Chapter 11 proceeding. Through December 31, 2003, the principal payments made to the qualifying facilities amounted to \$998 million.

At December 31, 2003, the Utility had agreements with 300 qualifying facilities for approximately 4,400 megawatts, or MW, that are in operation. Agreements for approximately 4,000 MW expire between 2004 and 2028. Qualifying facility power purchase agreements for approximately 400 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 agreements with 50 qualifying facilities that are not currently providing or expected to provide electricity. The total of approximately 4,400 MW consists of approximately 2,600 MW from cogeneration projects, 800 MW from wind projects and 1,000 MW from other projects, including biomass, waste-to-energy, geothermal, solar and hydroelectric. On January 22, 2004, the CPUC adopted a decision that requires California investor-owned electric utilities to allow owners of qualifying facilities with power purchase agreements expiring before the end of 2005 to extend these contracts for five years. Qualifying facility power purchase agreements accounted for approximately 20% of the Utility's 2003 electricity sources, approximately 25% of the Utility's 2002 electricity sources, and approximately 21% of the Utility's 2001 electricity resources. No single qualifying facility accounted for more than 5% of the Utility's 2003, 2002 or 2001 electricity sources.

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 made to qualifying facilities. Under the Settlement Agreement, the net after-tax amount of any qualifying facilities refunds, which the Utility actually realizes in cash, claim offsets or other credits, would reduce the \$2.21 billion after-tax regulatory asset. 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 2004 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 5% of 2003 electricity sources, approximately 4% of 2002 electricity sources and approximately 3% of 2001 electricity sources.

Other Third Party Power Agreements

Electricity Purchases to Satisfy the Residual Net Open Position

On January 1, 2003, the Utility resumed buying electricity to meet its residual net open position. During that year, more than 14,000 GWh of energy was bought and sold in the wholesale market to manage the 2003 residual net open position. Most of the Utility's contracts entered into in 2003 had terms of less than one year. During 2004 the Utility plans to enter into contracts of longer duration to satisfy its near-term residual net open position.

Renewable Energy Contracts

California law requires that, beginning in 2003, each California investor-owned electric utility 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 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 estimates the annual procurement target will initially require it to purchase about 750 GWh, of electricity from renewable resources each year. The Utility met its 2003 commitment and the CPUC has approved several contracts intended to meet its 2004 renewable energy requirement.

Western Area Power Administration

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 give the Utility access to WAPA's excess hydroelectric power and obligate the Utility to provide WAPA with electricity when its own resources are not sufficient to meet its requirements. The contracts are scheduled to terminate on December 31, 2004, but termination is subject to FERC approval, which the Utility expects to receive.

The costs to fulfill the Utility's obligations to WAPA under the contracts cannot be accurately estimated at this time since both the purchase price and the amount of electricity WAPA will need from the Utility in 2004 are uncertain. However, the Utility expects that the cost of meeting its contractual obligations to WAPA will be greater than the price the Utility receives from WAPA under the contracts. Although it is not indicative of future sales commitments or sales-related costs, WAPA's net amount purchased from the Utility was approximately 4,804 GWh, in 2003, 3,619 GWh in 2002 and 4,823 GWh in 2001.

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, 2003, the Utility owned 18,612 circuit miles of interconnected transmission lines operated at voltages of 500 kV to 60 kV and transmission substations with a capacity of 42,798 MVA. Electricity is transmitted across these lines and substations and is then distributed to customers through 120,428 circuit miles of distribution lines and substations with a capacity of 24,218 MVA. In 2003, the Utility delivered 80,156 GWh to its customers, including 8,979 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. The Utility is engaged in the following significant expansion projects:

Path 15 — WAPA and an independent transmission company, Trans-Elect NTD, Inc., are constructing 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 will interconnect the new 500 kV line at its existing substations at the line terminals and reconfigure 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 is expected to be operational in October 2004.

Jefferson-Martin — This project entails laying 28 miles of 230 kV underground transmission facilities from Redwood City to Daly City that will provide additional transmission system reliability in San Francisco and northern San Mateo County. This project is expected to be completed in December 2005.

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 2003, the Utility served approximately 3.9 million natural gas distribution customers. The total volume of natural gas throughput during 2003 was approximately 804 Bcf.

At December 31, 2003, the Utility's natural gas system consisted of 39,510 miles of distribution pipelines, 6,350 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 Gas Transmission Northwest Corporation, a subsidiary of NEGT, at the California-Oregon border. This line has a receipt capacity at the border of 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 2003, core customers represented over 99% of the Utility's total customers and 35% of its total natural gas deliveries, while noncore customers comprised less than 1% of the Utility's total customers and 65% 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 98% of core market demand, receive natural gas bundled services from the Utility.

In accordance with a ratemaking settlement agreement implemented in 1998 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 competitive 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 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 2002 California Gas Report updated the Utility’s annual natural gas requirements forecast for the years 2002 through 2023, forecasting average annual growth in the Utility’s natural gas deliveries of approximately 1.8%. 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.

2003 Natural Gas Deliveries

The following table shows the percentage of the Utility’s total 2003 natural gas deliveries represented by each of the Utility’s major customer classes:

(804 Bcf)

Residential Customers	25%
Transport only Customers (noncore)	65%
Commercial Customers	10%

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 1999 through 2003 (excluding subsidiaries) for natural gas, including the classification of sales and revenues by type of service:

	2003	2002	2001	2000	1999
Customers (average for the year):					
Residential	3,744,011	3,738,524	3,705,141	3,642,266	3,593,355
Commercial	208,857	206,953	205,681	203,355	203,342
Industrial	1,988	1,819	1,764	1,719	1,625
Other gas utilities	6	5	6	6	4
Total	3,954,862	3,947,301	3,912,592	3,847,346	3,798,326
Gas supply (MMcf):					
Purchased from suppliers in:					
Canada	196,278	210,716	209,630	216,684	230,808
California	(7,421)	19,533	20,352	32,167	18,956
Other states	102,941	67,878	76,589	75,834	107,226
Total purchased	291,798	298,127	306,571	324,685	356,990
Net (to storage) from storage	1,359	(218)	(27,027)	19,420	(980)
Total	293,157	297,909	279,544	344,105	356,010
Utility use, losses, etc.(1)	(14,307)	(16,393)	(8,988)	(62,960)	(47,152)
Net gas for sales	278,850	281,516	270,556	281,145	308,858
Bundled gas sales (MMcf):					
Residential	198,580	202,141	197,184	210,515	233,482
Commercial	79,891	78,812	72,528	66,443	70,093
Industrial	379	563	831	4,146	5,255
Other gas utilities	—	—	13	41	28
Total	278,850	281,516	270,556	281,145	308,858
Transportation only (MMcf):	525,353	508,090	646,079	606,152	484,218
Revenues (in millions):					
Bundled gas sales:					
Residential	\$ 1,836	\$ 1,379	\$ 2,308	\$ 1,681	\$ 1,543
Commercial	697	499	783	513	449
Industrial	1	3	16	35	24
Other gas utilities	1	1	—	—	—
Miscellaneous	(31)	127	(93)	84	(47)
Regulatory balancing accounts	68	11	(253)	132	(260)
Bundled gas revenues	2,572	2,020	2,761	2,445	1,709
Transportation service only revenue	284	316	375	338	287
Operating revenues	\$ 2,856	\$ 2,336	\$ 3,136	\$ 2,783	\$ 1,996
Selected Statistics:					
Average annual residential usage (Mcf)	53	54	53	59	65
Average billed bundled gas sales revenues per Mcf:					
Residential	\$ 9.25	\$ 6.82	\$ 11.70	\$ 7.98	\$ 6.61
Commercial	8.73	6.33	10.80	7.72	6.40
Industrial	2.48	4.35	19.15	8.53	4.69
Average billed transportation only revenue per Mcf	0.54	0.62	0.58	0.56	0.59

Net plant investment per customer	\$ 1,261	\$ 1,006	\$ 970	\$ 1,003	\$ 1,011
(1) Includes fuel for the Utility’s fossil fuel-fired generation plants.					
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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 2003, the Utility purchased approximately 292,000 MMcf of natural gas (net of the sale of excess supply) from 48 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 9.6% of the total natural gas volume the Utility purchased during 2003.

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 2003, the sale of excess supplies to parties located in California exceeded purchases from parties located in California.

	2003		2002		2001		2000		1999	
	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price	MMcf	Avg. Price
Canada	196,278	\$4.73	210,716	\$2.42	209,630	\$ 4.43	216,684	\$4.05	230,808	\$2.50
California(1)	(7,421)	\$3.39	19,533	\$2.88	20,352	\$11.55	32,167	\$8.20	18,956	\$2.45
Other states (substantially all U.S. southwest)	102,941	\$4.63	67,878	\$3.04	76,589	\$10.41	75,834	\$5.99	107,226	\$2.42
Total/weighted average	291,798	\$4.73	298,127	\$2.59	306,571	\$ 6.40	324,685	\$4.92	356,990	\$2.47

(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 2003, approximately 4% of the Utility's natural gas supplies came from various California producers and 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 475 miles of gas gathering pipelines, as well as dehydration, separation, regulation, odorization and metering equipment located at 62 stations. The gas gathering system is geographically dispersed and is located in 14 California counties. Approximately 120 MMcf per day of natural gas flows through the Utility's gas gathering system.

Interstate and Canadian Natural Gas Transportation Services Agreements

In 2003, approximately 67% of the Utility's natural gas supplies 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 2003, approximately 29% of the Utility's natural gas supplies 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, extend each of these natural gas transportation agreements for additional minimum terms ranging, depending on the particular agreement, from one to ten years. On the FERC-regulated pipelines, the Utility has a right of first refusal 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, 2003
			(In millions)
El Paso Natural Gas Company	10/31/2003	100	\$ 9.5
El Paso Natural Gas Company	12/31/2004	64	4.5
TransCanada NOVA Gas Transmission, Ltd.	12/31/2005	593	23.6
TransCanada PipeLines Ltd., B.C. System	10/31/2005	584	10.6
Gas Transmission Northwest Corporation	10/31/2005	610	55.0
Transwestern Pipeline Co.	03/31/2007	150	15.8
El Paso Natural Gas Company	03/31/2007	40	3.8
El Paso Natural Gas Company	04/30/2005	100	1.1

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 Electricity Industry

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 is expected to be completed in the second 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 2004 to address these issues. 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 existing agreements and procedures used when constructing facilities to interconnect new generators. Numerous parties have requested rehearing and a stay of the generator interconnection rules. Although the FERC has not yet ruled on the requests for rehearing, 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, filed proposed tariffs changes on January 20, 2004. It is uncertain when the FERC will act on the rehearing requests or the proposed tariff changes. Further, portions of the FERC's rulemaking may be affected by any energy legislation Congress may pass.

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 ratepayers 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, self-generation by the Utility's customers 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. 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 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 2005.

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. The California Attorney General has 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, proposed federal energy legislation was considered by the U.S. Senate. If adopted, the legislation would, among other things, repeal 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, is December 1, 2004. 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.

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, or (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.

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 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. The CPUC will also determine whether additional rules, conditions or changes are needed to adequately protect ratepayers and the public from dangers of abuse stemming from the holding company structure. The CPUC will investigate whether it should modify, change or add conditions to the holding company decisions, make further changes to the holding company structure, alter the standards under which the CPUC determines whether to authorize the formation of holding companies, otherwise modify the decisions or recommend statutory changes to the California legislature. As a result of the investigation, the CPUC may impose remedies, prospective rules, or conditions, as appropriate.

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." The three major California investor owned electric utilities and their parent holding companies had opposed this broader interpretation as being inconsistent with the prior 15 years' understanding of that condition as applying more narrowly to a priority on capital needed for investment purposes. The CPUC also interpreted the first priority condition as prohibiting a holding company from acquiring assets of its utility subsidiary for inadequate consideration and acquiring assets of its utility subsidiary at any price, if such acquisition would impair the utility's ability to fulfill its obligation to serve or to operate in a prudent and efficient manner. In the other 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 a related decision, the CPUC denied the motions filed by the California utility holding companies to dismiss the holding companies from the pending investigation on the basis that the CPUC lacks jurisdiction over the holding companies. However, in the interim decision interpreting the first priority condition discussed above, the CPUC separately dismissed PG&E Corporation (but no other utility holding company) as a respondent to the proceeding. In its written decision adopted on January 9, 2002, the CPUC stated that PG&E Corporation was being dismissed so that an appropriate legal forum could decide expeditiously whether adoption of the Utility's original proposed plan of reorganization would violate the first priority condition. On November 26, 2003, the California Court of Appeals for the First Appellate District in San Francisco agreed to hear the petitions for review of the CPUC's decisions. Oral argument before the appellate court is set for March 5, 2004.

PG&E Corporation and the Utility believe that they have complied with applicable statutes CPUC decisions, rules and orders. Under the Settlement Agreement the CPUC has agreed to dismiss PG&E Corporation from the CPUC's investigation as to past practices.

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. After the California Attorney General's complaint was filed, two other complaints containing substantially similar allegations were filed by the City and County of San Francisco and by a private plaintiff. 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 energy laws, regulations and regulatory mechanisms affecting the Utility. These sections are not an exhaustive description of all the energy 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 February 2004, the FERC is expected to consider ISO market monitoring and oversight in connection with the FERC's review of the ISO's standard 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 January 2000 to June 2001. In December 2002, a FERC administrative law judge issued an initial decision 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 (the only time period for which the FERC permitted refund claims), but that California buyers still owe the power suppliers approximately \$3.0 billion, leaving approximately \$1.2 billion in net unpaid bills.

During 2003, the FERC confirmed most of the administrative law judge's findings, 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 California Power Exchange, or PX, which operates solely to reconcile remaining refund amounts owed, to make compliance filings establishing refund amounts by March 2004. The ISO has indicated that it plans to make its compliance filing by August 2004. The actual refunds will not be determined until the FERC issues a final decision following the ISO and PX compliance filings. The FERC is uncertain when it will issue a final decision in this proceeding. In addition, future refunds could increase or decrease as a result of an alternative calculation proposed by the ISO, which incorporates revised data provided by the Utility and other entities.

Under the Settlement Agreement, the Utility and PG&E Corporation agreed to continue to cooperate with the CPUC and the State of California in seeking refunds from generators and other energy suppliers. The net after-tax amount of any refunds, claim offsets or other credits from generators or other energy suppliers relating to the Utility's ISO, PX, qualifying facilities or energy service provider costs that are actually realized in cash or by offset of creditor claims in its Chapter 11 proceeding would reduce the balance of the \$2.21 billion after-tax regulatory asset created by the Settlement Agreement.

The Utility has 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. The Utility currently estimates that the claims filed would have been reduced to approximately \$1.2 billion based on the refund methodology recommended in the administrative law judge's initial decision, resulting in a net liability of approximately \$1.0 billion after the approximately \$200 million pre-petition offset. The recalculation of market prices according to the revised methodology adopted by the FERC in its October 2003 decision could further reduce the amount of the suppliers' claims by several hundred million dollars. However, 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 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; and
- *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.

One of PG&E Corporation and the Utility's obligations under the Settlement Agreement is seeking to refinance the remaining unamortized pre-tax balance of the regulatory asset and related federal, state and franchise taxes using a securitized financing supported by a dedicated rate component that would require enactment of authorizing California legislation. On January 22, 2004, the CPUC approved proposed legislation, Senate Bill 772, that would authorize a dedicated rate component to securitize the regulatory asset and the related taxes. The California Assembly's Utilities and Commerce Committee approved the proposed legislation on February 2, 2004. The proposed legislation will next be considered by the California Assembly's Appropriations Committee. Under the Settlement Agreement, any adopted legislation must be satisfactory to the CPUC, the Utility and The Utility Reform Network, or TURN and the securitization must not adversely affect the Utility's credit ratings among other conditions.

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 the siting of all thermal power plants over 49 MW and administers public interest research and development funds, as well as renewable resource programs, including the renewable energy portfolio standard program.

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

Transition from Frozen Rates to Cost of Service Ratemaking

Frozen electricity rates, which began on January 1, 1998, were designed to allow the Utility to recover its authorized utility costs, and to the extent frozen rates generated revenues in excess of these costs, to recover the Utility's transition costs. Although the surcharges implemented in 2001 effectively increased the actual rate, under the frozen rate structure, increases in the Utility's authorized revenue requirements did not increase the Utility's revenues. In addition, DWR revenue requirements reduced the Utility's revenues under the frozen rate structure. As a result of revised electricity rates discussed below and a January 2004 CPUC decision determining that the rate freeze ended on January 18, 2001, the Utility expects that once approved by the CPUC, its rates will reflect its costs of service whereby the Utility's rates are calculated based on the aggregate of various authorized rate components. Changes in any individual revenue requirement will change customers' electricity rates.

On January 26, 2004, the Utility filed revised electricity rates with the CPUC based on the Utility's 2004 forecast revenue requirements and requested implementation of the rate changes. These rates reflect allocation of the Utility's revenue requirements in accordance with a January 20, 2004 rate design settlement agreement entered into with a number of consumer groups and government agencies, including TURN and the CPUC's Office of Ratepayer Advocates, or ORA. The rate design settlement agreement has been submitted to the

CPUC for approval. The revised rates and forecast revenue requirements are based on, and ultimately will be adjusted to reflect, pending or final CPUC decisions including:

- The Utility's 2003 GRC;
- The allocation of the DWR's 2004 revenue requirements;
- Pending energy supplier refunds, claim offsets or other credits pursuant to the Settlement Agreement; and
- The calculation of any over-collection of the surcharge revenues for 2003.

Based on the revised rates filed by the Utility on January 26, 2004, current electricity revenues are expected to be reduced by approximately \$860 million as compared to revenues generated at current rates. On February 11, 2004, a proposed decision was issued which, if ultimately approved by the CPUC, instead is expected to reduce the Utility's current electricity revenues by \$799 million. The most significant portion of the difference between the \$799 million included in the draft decision and the \$860 million filed by the Utility relates to a proposed decrease in the DWR's revenue requirement included in the Utility's January 26, 2004 rate filing. In the January 26, 2004 rate filing, the Utility had estimated that the DWR's revenue requirement would be reduced by approximately \$79 million related to the DWR's share of the settlement agreement of CPUC litigation reached with El Paso. However, the DWR protested the Utility's rate filing, indicating that the amount of its share of the El Paso settlement was unknown and that the DWR had not changed its revenue requirement as a result of the El Paso settlement.

The February 11, 2004 proposed decision orders the Utility to amend its January 26, 2004 filing containing the revised electricity rates before March 1, 2004. The CPUC is expected to consider the rate design settlement at its meeting on February 26, 2004. If approved, the new rates will be effective March 1, 2004 or shortly thereafter, and the revenue reduction will be retroactive to January 1, 2004.

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.

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 will 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.

DWR Allocated Contracts

The DWR provided approximately 29% of the electricity delivered to the Utility's customers for the year ended December 31, 2003. The DWR purchased the electricity under contracts with various generators and through open market purchases. 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. The DWR remains legally and financially responsible for the electricity procurement contracts.

The 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.

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 Services will be no less than A2 and the Utility's long-term issuer credit rating by Standard & Poors 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.

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. 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. In December 2002, the CPUC adopted a 2003 short-term procurement plan for the Utility. The CPUC also authorized the California investor-owned electric utilities to extend their planning into the first quarter of 2004 and directed the Utility to hedge its 2004 first quarter residual net open position with transactions entered into in 2003.

In December 2003, the CPUC approved the Utility's short-term 2004 procurement plan. In the January 2004 CPUC decision discussed below, the CPUC also adopted short-term procurement authority for 2005 for the utilities in order to allow them to begin the normal cycle for procuring products required for summer 2005, but contracts for 2005 cannot exceed one year.

On January 22, 2004, the CPUC adopted an interim decision establishing the long-term regulatory framework under which the California investor-owned electric utilities are required to plan for and procure

energy resources. The utilities are directed to meet resource needs first through cost effective energy efficiency, demand response, and renewable resources before considering the addition of conventional supply or transmission resources. The utilities are encouraged to have a diversified resource portfolio. The utilities are required to submit new long-term procurement plans in 2004 following workshops and the CPUC's adoption of specific resource adequacy criteria. The procurement plans are required to include a range of load forecasts for distributed generation and varying levels of community choice aggregation. The CPUC adopted a planning reserve requirement of 15% to 17% applicable to all load-serving entities, including the utilities, energy service providers and future community choice aggregators. The planning reserve requirement will be phased in by January 1, 2008, and intermediate benchmarks are to be established. In addition, beginning in 2005, 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. The CPUC also indicated that it will consider procurement incentive mechanisms for the utilities. The CPUC also continued the 5% target limitation on the utilities' reliance on the spot market to meet their energy needs.

Effective January 1, 2003, under 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 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. 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 aggregate over-collections or under-collections exceed 5% of the utility's prior year electricity procurement revenues,, excluding amounts collected for the DWR. These mandatory adjustments will continue until January 1, 2006.

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 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 is a party to a Transmission Control Agreement, or TCA, with the ISO and other participating transmission owners. As a transmission owner, the Utility is required to give two years notice and receive regulatory approval if it wishes to withdraw from the TCA. Under this agreement, the transmission owners, which also include Southern California Edison, or SCE, San Diego Gas & Electric Company and several municipal utilities, assign operational control of their electricity transmission systems to the ISO. In addition, as a party to the TCA, the Utility is responsible for a share of the costs of reliability must-run, or RMR, agreements between the ISO and owners of the power plants subject to RMR agreements, or RMR Plants. The Utility also is an owner of some of these RMR Plants for which the Utility receives revenue from the ISO. Under the RMR agreements, RMR Plants must remain available to generate electricity when needed for local transmission system reliability upon the ISO's demand.

At December 31, 2003, the ISO had RMR agreements for which the Utility could be obligated to pay the ISO an estimated \$446 million in net costs during the period January 1, 2004 to December 31, 2005. These costs are recoverable under applicable ratemaking mechanisms.

It is possible that the Utility may receive a refund of RMR costs that the Utility previously paid to the ISO. In June 2000, a FERC administrative law judge issued an initial decision approving rates that, if affirmed by the FERC, would require the subsidiaries of Mirant Corporation, or Mirant, 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 \$340 million, including interest, for availability of Mirant's RMR Plants under these agreements. However, 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. The Utility is unable to predict at this time when the FERC will issue a final decision on this issue, what the FERC's decision will be, and the amount of any refunds, which may be impacted by Mirant's Chapter 11 filing. It is uncertain how the resolution of this matter would be reflected in rates.

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 \$330 million in 2003. 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. A hearing in this matter was conducted at the FERC in October and November 2003 and an initial decision from the presiding administrative law judge is scheduled to be issued in March 2004.

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 18, 2003, the CPUC approved the Utility's application to retain the Gas Accord market structure for 2004 and 2005, and resolved the rates, and terms and conditions of service for the Utility's natural gas transportation and storage system for 2004. 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 natural gas transportation or storage revenues.

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 and public purpose program revenue requirements accumulate differences between authorized revenue requirements and actual base 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 January 22, 2004, the CPUC opened a rulemaking proceeding to establish policies and rules to ensure reliable, long-term supplies of natural gas to California. The order poses a series of questions and requires all gas utilities in California to provide information related to their natural gas procurement activities and their transportation and storage facilities. Among other things, the CPUC indicated that it may adopt rules whereby utilities could receive CPUC pre-approval of contracts for interstate pipeline capacity to support their natural gas procurement activities.

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.

Capacity Purchases on El Paso and Transwestern Pipelines

In July 2002, the CPUC ordered California investor-owned electric utilities to contract for additional amounts of El Paso pipeline capacity to gain firm access to the southwest natural gas producing basins. The CPUC believed that if the utilities had firm access rights, they would have been able to mitigate the gas price spikes that occurred during the energy crisis when shippers raised the price of gas at the California border. The CPUC pre-approved the costs of these contracts as just and reasonable. Since the July 2002 decision, the Utility has signed contracts for capacity on the El Paso pipeline costing approximately \$50.8 million for the period from November 2002 to December 2007. The July 2002 decision also ordered the California investor-owned electric utilities to retain their then-current interstate pipeline capacity levels and sell any excess capacity to third parties under short-term capacity release arrangements. It also ordered that, to the extent the California investor-owned electric utilities comply with the decision, they will be able to fully recover their costs associated with existing capacity contracts.

Under a previous CPUC decision, the Utility could not recover in rates any costs paid to Transwestern for natural gas pipeline capacity through 1997. The Utility pays approximately \$22 million in annual reservation charges under the Transwestern contract. The Gas Accord provided for partial recovery of Transwestern costs after 1997. In January 2004, the CPUC approved a settlement with TURN that allows the Utility to fully recover Transwestern costs retroactive to July 2003.

In December 2002, the CPUC granted the Utility’s request to recover in rates El Paso pipeline capacity costs and prepayments made to El Paso from all natural gas customers. The Utility began recovering these costs from all natural gas customers in March 2003. In January 2004, the CPUC re-allocated all the costs, including Transwestern costs incurred since July 2003, to the Utility’s core customers, because the pipeline capacity is used to serve core customers. The Utility’s noncore customers and core aggregation customers will receive a refund or bill credit for El Paso capacity costs paid by these customers between March 2003 and January 2004.

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, 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 sites that contain hazardous wastes 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.

Various multi-pollutant initiatives have been 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.

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 through 2004 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 regulatory initiatives, particularly at the federal level, 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 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, 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. However, at its July 10, 2003 meeting, the Central Coast Board did not renew the NPDES permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported this settlement agreement, and the Central Coast Board requested its staff to develop additional information on possible mitigation measures. The California Attorney General filed a claim in the Utility's Chapter 11 proceeding on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with the Diablo Canyon power plant's operation of its cooling water system. The Utility is seeking withdrawal of this claim from the Utility's Chapter 11 proceeding.

In addition, on April 9, 2002, the EPA proposed regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The regulations would 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 would be affected by this rulemaking. The proposed regulations call for 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 if the regulations are adopted as proposed. The final regulations are scheduled to be issued in February 2004.

In mid-January 2004, hexavalent chromium was detected in a sample taken from a groundwater monitoring well near the Utility's natural gas compressor station located near Topock, Arizona. This monitoring well is located approximately 150 feet from the Colorado River. While hexavalent chromium had been detected during previous sampling of other monitoring wells located further from the river, previous samples from this well had not shown any detectable hexavalent chromium. The Utility is cooperating with the California Department of Toxic Substances Control, or DTSC, other state agencies and appropriate federal agencies to develop a plan to ensure that the hexavalent chromium does not impact the Colorado River. Although implementation of the plan poses several technical and regulatory obstacles, the Utility does not expect the outcome in 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 \$8 million in 2003 and expects to spend approximately \$6 million in 2004 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 the Utility can estimate a range of reasonably likely cleanup costs. The Utility reviews its remediation liability quarterly for each site where the Utility 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 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 \$314 million at December 31, 2003, and \$331 million at December 31, 2002. During 2003, the liability was reduced by approximately \$17 million mainly due to reassessment of the estimated cost of remediation and remediation payments. The approximately \$314 million accrued at December 31, 2003, includes approximately \$104 million related to the pre-closing remediation liability associated with divested generation facilities, and approximately \$210 million related to remediation costs for those generation facilities that the Utility still owns, natural gas gathering sites, compressor stations, third-party disposal sites, and manufactured gas plant sites that are either 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 \$314 million environmental remediation liability, approximately \$147 million has been included in prior rate-setting proceedings, and the Utility expects that approximately \$116 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 ratepayers.

The Utility's undiscounted future costs could increase to as much as \$422 million if the other potentially responsible parties are not financially able to contribute to these costs or the extent of contamination or necessary remediation is greater than anticipated. The \$422 million amount does not include an estimate for the costs 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 liability exists.

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility's Chapter 11 proceeding for environmental remediation at numerous sites totaling approximately \$770 million. For most of these sites, remediation is ongoing in the ordinary course of business or the Utility is in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the cleanup. Other sites identified in the California Attorney General's claims may not, in fact, require remediation or cleanup actions. The Utility's Plan of Reorganization provides that the Utility intends to respond to these types of claims in the ordinary course of business and since the Utility has not argued that the Chapter 11 proceeding relieves the Utility of its obligations to respond to valid environmental remediation orders, the Utility believes the California Attorney General's claims seeking specific cash recoveries are unenforceable. Environmental claims in the ordinary course of business will not be discharged in the Utility's Chapter 11 proceeding and will pass through the Chapter 11 proceeding unimpaired.

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.

Under current operating procedures, the Utility believes that the Diablo Canyon power plant's existing spent fuel pools have sufficient capacity to enable it to operate through approximately 2007. It is unlikely that an interim or permanent DOE storage facility will be available by 2007. Therefore, the Utility has applied to the NRC for a license to build an on-site dry cask storage facility to store spent fuel at the Diablo Canyon power plant, pending disposal or storage at a DOE facility. The NRC has provided initial approvals for the facility and is expected to complete its authorization process in early 2004. The Utility also has initiated the process for obtaining a required California Coastal Commission permit for the facility. If the dry cask storage facility is not approved or is delayed, the Utility also is pursuing NRC approval of another storage option to install a temporary rack in each unit that would increase the on-site storage capability to permit the Utility to operate Unit 1 until 2010 and Unit 2 to 2011. During this additional period of time, the Utility also would pursue NRC approval for a high density reracking of both units, which, if approved, would allow the Utility to operate both units until shortly before the licenses expire in 2021 for Unit 1 and 2025 for Unit 2. If the Utility is unsuccessful in permitting and constructing the on-site dry cask storage facility, and it 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 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.

The Utility filed an application in December 2003 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 2006 and be completed in 2015.

The estimated nuclear decommissioning costs for the Diablo Canyon power plant and Humboldt Bay Unit 3 are approximately \$1.83 billion in 2003 dollars (or approximately \$5.25 billion in future dollars). These estimates are based on a 2002 decommissioning cost study, prepared in accordance with CPUC requirements, and 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 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. 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. The decision also set the annual decommissioning fund revenue requirement for

Humboldt Bay Unit 3 at approximately \$18.5 million and granted the Utility's request to begin decommissioning Humboldt Bay Unit 3 in 2006 instead of 2015. The decision further granted the Utility's request of approximately \$8.3 million for Humboldt Bay Unit 3 SAFSTOR operating and maintenance costs. The total adopted annual revenue requirement of approximately \$26.7 million represents a \$4.5 million decrease from the previously adopted revenue requirement of approximately \$31.2 million, which included amounts for both Humboldt Bay Unit 3 and Diablo Canyon. The CPUC also ordered the Utility to partially fund its 2004 revenue requirement with approximately \$10 million that the Utility collected in rates in 2000 for its nuclear decommissioning revenue requirement but that the Utility did not contribute to the trusts due to the Utility's cash conservation needs during the energy crisis.

The Utility's revenue requirements for nuclear decommissioning costs are recovered from ratepayers 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 ratepayers 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 2003, the Utility collected approximately \$22.6 million in rates and contributed approximately \$21.3 million, on an after-tax basis, to the nuclear decommissioning trusts. For 2004, the Utility is authorized to collect approximately \$18.5 million in rates for decommissioning Humboldt Bay Unit 3. Of this amount, the Utility expects to contribute approximately \$13.3 million, on an after-tax basis, to the qualified and non-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 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 funds held in the trusts, net of authorized disbursements from the trusts and management and administrative fees, are reinvested. Amounts may not be released from the decommissioning trusts until authorized by the CPUC. At December 31, 2003, the Utility had accumulated decommissioning trust funds with an estimated fair value of approximately \$1.4 billion, based on quoted market prices and net of deferred taxes on unrealized gains.

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. 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 with the CPUC. 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.

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 2005.

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 in the U.S. Bankruptcy Court for the Northern District of California. The factors that caused the Utility to take this action are discussed in MD&A and in Note 2 of the Notes to the Consolidated Financial Statements in the Annual Report, which is incorporated by reference into this report. During the Utility's Chapter 11 proceeding, the Utility has retained control of its assets and is authorized to operate its business as a debtor-in-possession while it is subject to the jurisdiction of the bankruptcy court.

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. 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. Both entities are subsidiaries of J.P. Morgan Chase & Co.

In September 2001, PG&E Corporation and the Utility submitted a plan of reorganization that proposed to disaggregate the Utility's current businesses. The CPUC, later joined by the Official Committee of Unsecured Creditors, or OCC, submitted a competing proposed plan of reorganization that did not provide for disaggregation of the Utility's businesses. As discussed above, on December 19, 2003, the CPUC, PG&E Corporation and the Utility entered into the Settlement Agreement that contemplated a new plan of reorganization to supercede the competing plans. Under the Settlement Agreement, the Utility remains vertically integrated. On December 22, 2003, the bankruptcy court confirmed the Plan of Reorganization that fully incorporates the Settlement Agreement.

On December 30, 2003, the City of Palo Alto filed a motion with the bankruptcy court for a stay of the bankruptcy court's order confirming the Plan of Reorganization pending the City of Palo Alto's appeal of the confirmation order to the U.S. District Court for the Northern District of California, or District Court. The two CPUC Commissioners who did not vote to approve the Settlement Agreement joined in the City of Palo Alto's motion. On January 5, 2004, the bankruptcy court denied the request for a stay. In January 2004, the City of Palo Alto and the two CPUC Commissioners filed appeals in the District Court of the bankruptcy court's confirmation order.

On January 20, 2004, the City of Palo Alto, the City and County of San Francisco, or CCSF, and Aglet Consumer Alliance, or Aglet, filed separate applications with the CPUC requesting that the CPUC rehear and reconsider its decision approving the Settlement Agreement. CCSF, Aglet and the ORA also filed a joint application for rehearing. Although the CPUC is not required to act on the applications within a specific time period, if the CPUC has not acted on an application within 60 days, that application may be deemed denied for purposes of seeking judicial review.

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 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.

As required by the Settlement Agreement, the Utility has requested a stay of all proceedings before the FERC, the NRC, the SEC and other regulatory agencies relating to approvals sought to implement the original plan of reorganization. The Utility also has suspended all actions to obtain or transfer licenses, permits and franchises to implement the original plan of reorganization. On the effective date of the confirmed Plan of Reorganization or as soon thereafter as practicable, the Utility and PG&E Corporation will withdraw or abandon all applications for these regulatory approvals.

There are several legal proceedings still pending in connection with the original plan of reorganization. On May 14, 2003, the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit, heard oral argument in the appeal filed by the CPUC and other parties of an order issued by the District Court finding that the U.S. Bankruptcy Code expressly preempts “non-bankruptcy laws that would otherwise apply to bar, among other things, transactions necessary to implement the reorganization plan.” The District Court’s order had reversed an earlier ruling by the bankruptcy court that found that bankruptcy law did not expressly preempt certain non-bankruptcy laws in connection with the original plan of reorganization, but that it could be implied to preempt non-bankruptcy laws in certain circumstances.

On November 19, 2003, the Ninth Circuit issued a decision agreeing with the District Court’s finding that a Chapter 11 reorganization plan expressly preempts otherwise applicable non-bankruptcy laws. However, the Ninth Circuit ruled that the scope of such express preemption is limited to those non-bankruptcy laws relating to financial condition. The Ninth Circuit determined that neither the bankruptcy court nor the District Court had applied the proper standard of express preemption. It therefore reversed the District Court’s August 30, 2002, decision and remanded the matter back to the bankruptcy court for further proceedings to determine whether the Utility’s and PG&E Corporation’s original plan of reorganization satisfied the express preemption standard announced by the Ninth Circuit.

Although the Ninth Circuit stated that the question of implied preemption was not before it in the appeal, it reaffirmed that implied preemption could apply under the Bankruptcy Code, even if express preemption did not. On December 10, 2003, the Utility and PG&E Corporation filed a petition to rehear the Ninth Circuit’s decision with the panel that issued the decision, and suggested that the full Ninth Circuit should rehear the issue, since it conflicts with other Ninth Circuit cases and cases from other Circuits.

The Utility’s current Settlement Agreement and the confirmed Plan of Reorganization do not rely on the bankruptcy law preemption issues addressed in the Ninth Circuit decision.

Implementation of the Plan of Reorganization is subject to various conditions, including the consummation of the public offering of long-term debt, the receipt of investment grade credit ratings and final CPUC approval of the Settlement Agreement. For purposes of these conditions, final approval means approval on behalf of the CPUC that is not subject to any pending appeal or further right of appeal, or approval on behalf of the CPUC that, although subject to a pending appeal or further right of appeal, has been agreed by the Utility and PG&E Corporation to constitute final approval. Thus, the terms of the Plan of Reorganization permit the Utility and PG&E Corporation to cause the Plan of Reorganization to become effective (and permit the Utility to issue the long term debt) while the CPUC’s approvals are subject to pending appeals or further rights of appeal. Until certain conditions or events regarding the effectiveness of the Plan of Reorganization discussed above are resolved further, PG&E Corporation and the Utility cannot conclude that the applicable accounting probability standard needed to record the regulatory assets contemplated by the Settlement Agreement has been met. PG&E Corporation and the Utility believe that the Utility and the long-term debt to be issued will receive investment grade credit ratings . The Utility has targeted April 2004 to complete the sale of the long-term debt, which the Utility expects to be the last condition of the Plan of Reorganization to be satisfied. The Plan of Reorganization provides that the effective date will occur 11 business days after all the conditions have been satisfied or, with respect to all conditions except those relating

to investment grade credit ratings, waived by PG&E Corporation and the Utility. There can be no assurance that the Settlement Agreement will not be modified on rehearing or appeal or that the Plan of Reorganization will become effective.

Chapter 11 Filing of NEGT

On July 8, 2003, NEGT 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. On July 29, 2003, two additional subsidiaries of NEGT also filed voluntary Chapter 11 petitions. NEGT also has filed a proposed plan of reorganization with the bankruptcy court that, if implemented, would eliminate PG&E Corporation's equity interest in NEGT and its subsidiaries.

In anticipation of NEGT's Chapter 11 filing, PG&E Corporation's representatives who previously served as directors of NEGT resigned on July 7, 2003 and were replaced with directors who are not affiliated with PG&E Corporation. As a result, PG&E no longer retains significant influence over NEGT. Accordingly, effective July 8, 2003, NEGT's results of operations are no longer consolidated with those of PG&E Corporation and its results of operations through July 7, 2003 and for prior years have been reclassified as discontinued operations.

For more information, see Note 5 of the Notes to the Consolidated Financial Statements in the Annual Report, which is incorporated by reference and filed as Exhibit 13 to this report.

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 will 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. Therefore, the Utility filed a motion to stay consideration of the appeal of the filed rate case. On August 11, 2003, the Ninth Circuit issued an order staying proceedings in the filed rate case. The Ninth Circuit has ordered the parties to file a status report by July 30, 2004.

In re: Natural Gas Royalties Qui Tam Litigation

This litigation involves the consolidation of approximately 77 False Claims Act cases filed in various federal district courts by Jack J. Grynberg (referred to as a relator in the terminology of the False Claims Act) on behalf of the United States of America against more than 330 defendants, including the Utility. The cases were consolidated for pretrial purposes in the U.S. District Court for the District of Wyoming. The current case grows out of prior litigation brought by the same relator in 1995 that was dismissed in 1998.

Under procedures established by the False Claims Act, the United States, acting through the DOJ, is given an opportunity to investigate the allegations and to intervene in the case and take over its prosecution if it chooses to do so. In April 1999, the DOJ declined to intervene in any of the cases.

The complaints allege that the various defendants, most of whom are natural gas pipeline companies or their affiliates, incorrectly measured the volume and heating content of natural gas produced from federal or Indian leases. As a result, the relator alleges that the defendants underpaid, or caused others to underpay, the royalties that were due to the United States for the production of natural gas from those leases.

The complaints do not seek a specific dollar amount or quantify the royalties claim. The complaints seek unspecified treble damages, civil penalties and reasonable expenses associated with the litigation. The relator has filed a claim in the Utility's Chapter 11 case for \$2.5 billion, \$2.0 billion of which is based upon the relator's calculation of penalties against the Utility.

The Utility believes the allegations to be without merit and intends to present a vigorous defense. The Utility believes that the ultimate outcome of the litigation will not have a material adverse effect on the Utility's financial condition or results of operations.

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 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 the

settlement agreement is that the Central Coast Board renew Diablo Canyon's NPDES permit. However, 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 its staff to develop additional information on possible mitigation measures.

The California Attorney General has filed a claim in the Utility's Chapter 11 case on behalf of the Central Coast Board seeking unspecified penalties and other relief in connection with the Diablo Canyon power plant's operation of its cooling water system. The Utility is seeking withdrawal of this claim.

On June 13, 2002, the Utility received a draft enforcement order from the California Department of Toxic Substances Control, or DTSC, alleging that the Utility's Diablo Canyon power plant failed to maintain an adequate financial assurance mechanism to cover closure costs for its hazardous waste storage facility for several months after the Utility's Chapter 11 filing in 2001. The draft order sought \$340,000 in civil penalties for the period during which the Utility were unable to comply with the DTSC's requirements. The draft order also directed the Utility to maintain appropriate financial assurance on a going forward basis. On September 4, 2002, the Utility received a draft enforcement order from DTSC alleging a variety of hazardous waste violations at the Utility's Diablo Canyon power plant. This draft order sought \$24,330 in civil penalties.

In April 2003, the Utility signed a final settlement agreement with DTSC, under which the Utility agreed to pay approximately \$165,000 in civil penalties and approximately \$30,000 in costs. The Utility paid these amounts in May 2003. The California Attorney General filed a claim in the Utility's Chapter 11 case on behalf of DTSC, and the Utility is currently seeking withdrawal of those portions of the claim relating to financial assurance and hazardous waste matters.

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

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

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 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 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. (On January 9, 2002, the CPUC issued a decision interpreting the holding company condition regarding capital requirements (which it terms 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." The three major California investor-owned energy utilities and their parent holding companies had opposed the broader interpretation, first contained in a proposed decision released for comment on December 26, 2001, as being inconsistent with the prior 15 years' understanding of that condition as applying more narrowly to a priority on capital needed for investment purposes. The three major California investor-owned utilities and their parent holding companies appealed the CPUC's interpretation of the first priority condition to various state appellate courts. The CPUC moved to consolidate all proceedings in the San Francisco state appellate court. The CPUC's request for consolidation was granted and all the petitions are now before the California Court of Appeal for the First Appellate District in San Francisco, California. Oral argument is scheduled for March 5, 2004.

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 San Francisco 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 San Francisco Superior Court, omitting the allegations concerning PG&E Corporation's participation in the Utility's Chapter 11 proceedings. PG&E Corporation and the directors named in the complaint have filed motions to strike certain allegations of the amended complaint. On February 28, 2003, the court denied the three motions to strike on the grounds that they were premature and stated that it would defer making a judgment on the merits of the defendants' arguments until the factual context of the cases was more fully developed.

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 San Francisco 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.

In addition, a third case, entitled *Cynthia Behr v. PG&E Corporation, et al.*, was filed on February 14, 2002, by a private plaintiff (who also has filed a claim under Chapter 11) in Santa Clara Superior Court also alleging a violation of Section 17200. The Behr complaint also names the directors of PG&E Corporation and the Utility as defendants. The allegations of the complaint are similar to the allegations contained in the California Attorney General's complaint, but also include allegations of conspiracy, fraudulent transfer and violation of the California bulk sales laws. The plaintiff requests the same remedies as the California Attorney General, and, in addition, requests damages, attachment and restraints upon the transfer of defendants' property. In March 2002, PG&E Corporation filed a notice of removal in the bankruptcy court to transfer the complaint to the bankruptcy court. Subsequently, the plaintiff filed a motion to remand the action to state court. In its June 2002 ruling mentioned above as to the California Attorney General's and the City's cases, the bankruptcy court retained jurisdiction over Behr's fraudulent transfer claim and bulk sales claim, finding them to belong to the Utility's estate. The bankruptcy court remanded Behr's Section 17200 claim to the Santa Clara Superior Court. Both parties appealed the bankruptcy court's remand order to the District Court.

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

On July 24, 2003, the District Court heard oral argument on the appeal and cross-appeal of the bankruptcy court's remand order in the three cases. 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 would release 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 San Francisco Superior Court, where a status conference has been scheduled for February 24, 2004. The California Attorney General and the City and County of San Francisco have appealed this ruling to the Ninth Circuit. The defendants have filed motions to dismiss the appeals. No proceedings have been scheduled in bankruptcy court regarding the restitution claims. Under Section 17200, the California Attorney General is entitled to seek civil penalties of \$2,500 against each defendant for each violation of Section 17200. The California Attorney General's complaint asserted that the total civil penalties would be not less than \$500 million. The bankruptcy court's confirmation order provides that the California Attorney General's and the City and County of San Francisco's claims are not released in connection with implementation of the Plan of Reorganization.

The defendants filed a motion to seek clarification from the District Court regarding whether the District Court's October 2003 order reaches the restitution claims against the director defendants, as distinct from PG&E Corporation. At a hearing in November 2003, the District Court confirmed that its October 2003 order holds that the defendants' restitution claims against the directors are also the property of the Utility's estate.

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' motion 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 13 summary judgment motions or motions in limine (motions to exclude potentially prejudicial information) challenging the claims of the trial test plaintiffs. Two of these motions are scheduled for hearing in the first quarter of 2004, with the others to be scheduled thereafter. The trial of the test cases is scheduled to begin in March 2004. The Utility's motion to dismiss the complaint in the *Adams* case was granted. The plaintiffs in that case have until April 12, 2004 to file an amended complaint.

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, 2003 are as follows:

Name	Age	Position
R. D. Glynn, Jr.	61	Chairman of the Board, Chief Executive Officer, and President
P. A. Darbee	50	Senior Vice President and Chief Financial Officer
C. P. Johns	43	Senior Vice President and Controller
D. D. Richard, Jr.	53	Senior Vice President, Public Affairs; Senior Vice President, Public Affairs, Pacific Gas and Electric Company
G. R. Smith	55	Senior Vice President; President and Chief Executive Officer, Pacific Gas and Electric Company
G. B. Stanley	57	Senior Vice President, Human Resources
B. R. Worthington	54	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, 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.

Name	Position	Period Held Office
R. D. Glynn, Jr.	Chairman of the Board, Chief Executive Officer and President	January 1, 1998 to present
	Chairman of the Board, Pacific Gas and Electric Company	January 1, 1998 to present
P. A. Darbee	Senior Vice President and Chief Financial Officer	July 9, 2001 to present
	Senior Vice President, Chief Financial Officer, and Treasurer	September 20, 1999 to July 8, 2001
	Vice President and Chief Financial Officer, Advance Fibre Communications, Inc.	June 30, 1997 to September 19, 1999
C. P. Johns	Senior Vice President and Controller	September 19, 2001 to present
	Vice President and Controller	July 1, 1997 to September 18, 2001
	Vice President and Controller, Pacific Gas and Electric Company	June 1, 1996 to December 31, 1999
D. D. Richard, Jr.	Senior Vice President, Public Affairs	October 18, 2000 to present
	Vice President, Governmental Relations	July 1, 1997 to October 17, 2000
	Senior Vice President, Public Affairs, Pacific Gas and Electric Company	May 1, 1998 to present
	Senior Vice President, Governmental and Regulatory Relations, Pacific Gas and Electric Company	July 1, 1997 to April 30, 1998
G. B. Stanley	Senior Vice President, Human Resources	January 1, 1998 to present
	Senior Vice President, National Energy & Gas Transmission, Inc.	July 1, 2000 to July 7, 2003
	Vice President, Human Resources	June 1, 1997 to December 31, 1997
B. R. Worthington	Senior Vice President and General Counsel	June 1, 1997 to present
	Vice President, National Energy & Gas Transmission, Inc.	January 20, 1999 to July 1, 2000

“The names, ages and position’s 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, 2003 are as follows:

Name	Age	Position
G. R. Smith	55	President and Chief Executive Officer
K. M. Harvey	45	Senior Vice President — Chief Financial Officer, and Treasurer
T. B. King	42	Senior Vice President and Chief of Utility Operations
R. J. Peters	53	Senior Vice President and General Counsel
D. D. Richard, Jr.	53	Senior Vice President, Public Affairs
G. M. Rueger	53	Senior Vice President, Generation and Chief Nuclear Officer

All officers of the Utility serve at the pleasure of the Board of Directors. During the past five years, 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
G. R. Smith	President and Chief Executive Officer	June 1, 1997 to present
K. M. Harvey	Senior Vice President, PG&E Corporation	January 1, 1999 to present
	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
	Senior Vice President, Chief Financial Officer, and Treasurer	July 1, 1997 to December 31, 1999
T. B. King	Senior Vice President and Chief of Utility Operations	November 1, 2003 to present
	Senior Vice President, PG&E Corporation	January 1, 1999 to October 31, 2003
	President, PG&E National Energy Group, Inc.	November 15, 2002 to July 8, 2003
	President and Chief Operating Officer, PG&E Gas Transmission Corporation	August 27, 2002 to July 8, 2003
	President and Chief Operating Officer, Gas Transmission, PG&E National Energy Group, Inc.	August 9, 2002 to November 14, 2002
	President and Chief Operating Officer, West Region, PG&E National Energy Group, Inc.	July 1, 2000 to August 8, 2002
	President and Chief Operating Officer, PG&E Gas Transmission Corporation	November 23, 1998 to September 10, 2002*
R. J. Peters	Senior Vice President and General Counsel	January 1, 1999 to present

Name	Position	Period Held Office
D. D. Richard, Jr.	Senior Vice President, Public Affairs (Please refer to description of business experience for executive officers of PG&E Corporation above.)	May 1, 1998 to present
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

PART II

Item 5. Market for the Registrant's Common Equity and Related Shareholder Matters.

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 2003 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report. As of February 17, 2004, there were 110,740 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York, Pacific, and 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 — Dividend Policy" of the 2003 Annual Report.

On July 2, 2003, PG&E Corporation completed the offer and sale of \$600 million of 6 7/8% Senior Secured Notes due 2008 pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act of 1933, or Act. The net proceeds of the offering, approximately \$581 million, together with cash on hand, were used to repay the principal balance outstanding under PG&E Corporation's October 2002 credit agreement of approximately \$720 million, plus \$15 million of accrued in-kind interest and a \$52 million prepayment premium. The payment resulted in the termination of PG&E Corporation's existing credit agreement and the release of liens on PG&E Corporation's shares of NEGT. Lehman Brothers acted as principal underwriters. The notes were offered and sold only to "qualified institutional buyers" as defined in Rule 144A under the Act in compliance with Rule 144A under the Act, and in offers and sales that occur outside the U.S. to persons other than U.S. persons, or foreign purchasers, which include dealers or other professional fiduciaries in the U.S. acting on a discretionary basis for foreign beneficial owners, other than an estate or trust, in offshore transactions meeting the requirements of Rule 903 of Regulation S under the Act. For more information, see Note 3 to the "Notes to Consolidated Financial Statements" of PG&E Corporation contained in the 2003 Annual Report, which information is hereby incorporated by reference and filed as part of Exhibit 13 to this report.

Pacific Gas and Electric Company did not make any sales of unregistered equity securities during 2003, the period covered by this report.

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 2003 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 2003 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 2003 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 2003 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 2003 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 Common 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 disclosure controls and procedures as of December 31, 2003, PG&E Corporation’s and Pacific Gas and Electric Company’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 Pacific Gas and Electric Company’s 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.

There were no changes in internal controls over financial reporting that occurred during the quarter ended December 31, 2003, that have materially affected, or are reasonably likely to materially affect, PG&E Corporation’s or Pacific Gas and Electric Company’s controls over financial reporting.

PART III

Item 10. *Directors and Executive Officers of the Registrant.*

Directors

The authorized number of directors of PG&E Corporation currently is 10, and the authorized number of directors of the Utility currently is 11. On February 18, 2004, each Board of Directors approved amendments to the respective company’s bylaws to reduce the authorized number of directors effective upon adjournment of the 2004 Joint Annual Meeting of shareholders. After these amendments become effective, the bylaws will provide that the authorized number of directors of PG&E Corporation will be eight, and the authorized number of directors of Pacific Gas and Electric Company will be nine.

Information is provided below about the directors of PG&E Corporation and the Utility, including their principal occupations for the past five years, certain other directorships, age, and length of service as a director

of PG&E Corporation and the Utility. The directors of PG&E Corporation and the directors of the Utility are the same, except that Gordon R. Smith is a director of the Utility only.

David R. Andrews. Mr. Andrews is Senior Vice President Government Affairs, General Counsel, and Secretary of PepsiCo, Inc. (food and beverage businesses), and has held that position since February 2002. Prior to joining PepsiCo, Inc., Mr. Andrews was a partner in the law firm of McCutchen, Doyle, Brown & Enersen, LLP from May 2000 to January 2002 and from 1981 to July 1997. From August 1997 to April 2000, he served as the legal advisor to the U.S. Department of State and former Secretary Madeleine Albright. Mr. Andrews, 62, has been a director of PG&E Corporation and the Utility since 2000. He also serves as a director of UnionBanCal Corporation.

Leslie S. Biller. Mr. Biller is retired Vice Chairman and Chief Operating Officer of Wells Fargo & Company (financial services and retail banking). He held that position from November 1998 until his retirement in October 2002. Mr. Biller was President and Chief Operating Officer of Norwest Corporation (bank holding company) from 1997 until it merged with Wells Fargo & Company in 1998. Mr. Biller, 55, has been an advisory director of PG&E Corporation and the Utility since January 2003, and was elected a director of PG&E Corporation and the Utility on February 18, 2004. He also serves as a director of Ecolab Inc.

David A. Coulter. Mr. Coulter is Vice Chairman of J.P. Morgan Chase & Co. and J.P. Morgan Chase Bank, responsible for its investment bank, investment management, and private banking., and has held that position since January 2001. Prior to the merger with J.P. Morgan & Co. Incorporated, he was Vice Chairman of The Chase Manhattan Corporation (bank holding company) from August 2000 to December 2000. He was a partner in the Beacon Group, L.P. (investment banking firm) from January 2000 to July 2000, and was Chairman and Chief Executive Officer of BankAmerica Corporation and Bank of America NT&SA from May 1996 to October 1998. Mr. Coulter, 56, has been a director of PG&E Corporation and the Utility since 1996. He also serves as a director of Strayer Education, Inc.

C. Lee Cox. Mr. Cox is retired Vice Chairman of AirTouch Communications, Inc. and retired President and Chief Executive Officer of AirTouch Cellular (cellular telephone and paging services). He was an executive officer of AirTouch Communications, Inc. and its predecessor, PacTel Corporation, from 1987 until his retirement in April 1997. Mr. Cox, 62, has served as a director of PG&E Corporation and the Utility since 1996.

William S. Davila. Mr. Davila is President Emeritus of The Vons Companies, Inc. (retail grocery). He was President of The Vons Companies, Inc. from 1986 until his retirement in May 1992. Mr. Davila, 72, has been a director of the Utility since 1992 and a director of PG&E Corporation since 1996. He also serves as a director of The Home Depot, Inc.

Robert D. Glynn, Jr. Mr. Glynn is Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation and Chairman of the Board of the Utility. He has been an officer of PG&E Corporation since December 1996 and an officer of the Utility since January 1988. Mr. Glynn, 61, has been a director of the Utility since 1995 and a director of PG&E Corporation since 1996.

David M. Lawrence, MD Dr. Lawrence is retired Chairman and Chief Executive Officer of Kaiser Foundation Health Plan, Inc. and Kaiser Foundation Hospitals, and was an executive officer of those companies from 1991 until his retirement in 2002. Dr. Lawrence, 63, has been a director of the Utility since 1995 and a director of PG&E Corporation since 1996. He also serves as a director of Agilent Technologies Inc. and McKesson Corporation.

Mary S. Metz. Dr. Metz is President of S. H. Cowell Foundation, and has held that position since January 1999. Prior to that date, she was Dean of University Extension, University of California, Berkeley from July 1991 to June 1998. Dr. Metz, 66, has been a director of the Utility since 1986 and a director of PG&E Corporation since 1996. She also serves as a director of Longs Drug Stores Corporation, SBC Communications Inc., and UnionBanCal Corporation.

Carl E. Reichardt. Mr. Reichardt served as Vice Chairman of Ford Motor Company from October 2001 to July 2003. He is retired Chairman of the Board and Chief Executive Officer of Wells Fargo &

Company (bank holding company) and Wells Fargo Bank, N.A. He was an executive officer of Wells Fargo Bank from 1978 until his retirement in December 1994. Mr. Reichardt, 72, has been a director of the Utility since 1985 and a director of PG&E Corporation since 1996. He also serves as a director of ConAgra Foods, Inc. and Ford Motor Company.

Gordon R. Smith. Mr. Smith is President and Chief Executive Officer of the Utility, and has been an officer of the Utility since 1980. Mr. Smith, 56, has been a director of the Utility since 1997.

Barry Lawson Williams. Mr. Williams is President of Williams Pacific Ventures, Inc. (business investment and consulting), and has held that position since 1987. He also served as interim President and Chief Executive Officer of the American Management Association (management development organization) from November 2000 to June 2001. Mr. Williams, 59, has been a director of the Utility since 1990 and a director of PG&E Corporation since 1996. He also serves as a director of CH2M Hill Companies, Ltd., The Northwestern Mutual Life Insurance Company, R.H. Donnelley Corporation, The Simpson Manufacturing Company Inc., and SLM Corporation.

Executive Officers

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 48 through 50 in Part I of this report.

Section 16 Beneficial Ownership Reporting Compliance

In accordance with Section 16(a) of the Securities Exchange Act of 1934 and Securities and Exchange Commission (SEC) regulations, PG&E Corporation’s and the Utility’s directors and certain officers, and persons who own greater than 10 percent of PG&E Corporation’s or the Utility’s equity securities must file reports of ownership and changes in ownership of such equity securities with the SEC and the principal national securities exchange on which those securities are registered, and must furnish PG&E Corporation or the Utility with copies of all such reports they file.

Based solely on its review of copies of such reports received or written representations from certain reporting persons, PG&E Corporation and the Utility believe that during 2003 all filing requirements applicable to their respective directors, officers, and 10 percent shareholders were satisfied, except that a Statement of Changes of Beneficial Ownership of Securities on Form 4 was filed late for Thomas B. King due to internal corporate administrative delays. No information is reported for individuals during periods in which they were not directors, officers, or 10 percent shareholders of the respective company.

Audit Committee Members and Financial Expert

The members of the Audit Committees for each of PG&E Corporation and the Utility are C. Lee Cox, David R. Andrews, William S. Davila, Mary S. Metz, and Barry Lawson Williams.

The Boards of Directors of PG&E Corporation and the Utility each have determined that both C. Lee Cox and Barry Lawson Williams, members of each company’s Audit Committee, each are “audit committee financial experts” as defined by the SEC regulations, implementing Section 407 of the Sarbanes-Oxley Act of 2002. Each Board of Directors has determined that Mr. Cox and Mr. Williams each are “independent” as defined by current listing standards of the New York Stock Exchange and the American Stock Exchange, as applicable.

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.

Item 11. *Executive Compensation.*

Compensation of Directors

Each director who is not an officer or employee of PG&E Corporation or the Utility receives a quarterly retainer of \$7,500 plus a fee of \$1,000 for each Board or Board committee meeting attended. Non-employee directors who chair Board committees receive an additional quarterly retainer of \$625. Under the Deferred Compensation Plan for Non-Employee Directors, directors of PG&E Corporation or the Utility may elect to defer all or part of such compensation for varying periods. Directors who participate in the Deferred Compensation Plan may convert their deferred compensation into common stock equivalents, the value of which is tied to the market value of PG&E Corporation common stock. Alternatively, participating directors may elect that their deferred compensation be invested in the Utility Bond Fund.

No director who serves on both the PG&E Corporation and Utility Boards and corresponding committees is paid additional compensation for concurrent service on the Utility's Board or its committees, except that separate meeting fees are paid for each meeting of the Utility Board, or a Utility Board committee, that is not held concurrently or sequentially with a meeting of the PG&E Corporation Board or a corresponding PG&E Corporation Board committee. It is the usual practice of PG&E Corporation and the Utility that meetings of the respective Boards and corresponding committees are held concurrently and, therefore, that a single meeting fee is paid to each director for each set of meetings.

Directors of PG&E Corporation or the Utility are reimbursed for reasonable expenses incurred for participating in Board meetings, committee meetings, or other activities undertaken on behalf of PG&E Corporation or the Utility.

Effective January 1, 1998, the PG&E Corporation Retirement Plan for Non-Employee Directors was terminated. Directors who had accrued benefits under the Plan were given a one-time option of receiving at retirement the benefit accrued through 1997, or of converting the present value of their accrued benefit into a PG&E Corporation common stock equivalent investment held in the Deferred Compensation Plan for Non-Employee Directors. The payment of frozen accrued retirement benefits, or distributions from the Deferred Compensation Plan attributable to the conversion of retirement benefits, cannot be made until the later of age 65 or retirement from the Board.

Under the Non-Employee Director Stock Incentive Plan, which is a component of the PG&E Corporation Long-Term Incentive Program, on the first business day of January of each year, each non-employee director of PG&E Corporation is entitled to receive stock-based grants with a total aggregate equity value of \$30,000, composed of (1) restricted shares of PG&E Corporation common stock valued at \$10,000 (based on the closing price of PG&E Corporation common stock on the first business day of the year), and (2) a combination, as elected by the director, of non-qualified stock options and common stock equivalents with a total equity value of \$20,000, based on equity value increments of \$5,000. The exercise price of stock options is equal to the market value of PG&E Corporation common stock (i.e., the closing price) on the date of grant. Restricted stock and stock options vest over the five-year period following the date of grant, except that restricted stock and stock options will vest immediately upon mandatory retirement from the Board, upon a director's death or disability, or in the event of a change in control. Common stock equivalents awarded to non-employee directors are payable only in the form of PG&E Corporation common stock following a

director's retirement from the Board, upon a director's death or disability, or in the event of a change in control. Unvested awards are forfeited if the recipient ceases to be a director for any other reason.

On January 2, 2003, each non-employee director received 684 restricted shares of PG&E Corporation common stock. In addition, directors who were granted stock options received options to purchase 1,101 shares of PG&E Corporation common stock for each \$5,000 increment of equity value (subject to the aggregate \$20,000 limit) at an exercise price of \$14.61 per share, and directors who were granted common stock equivalents received 342 common stock equivalent units for each \$5,000 increment of equity value (subject to the aggregate \$20,000 limit).

Summary Compensation Table

This table summarizes the principal components of compensation paid to the Chief Executive Officers and the other most highly compensated executive officers of PG&E Corporation and the Utility during the past year.

Name and Principal Position	Year	Annual Compensation			Long-Term Compensation			
		Salary (\$)	Bonus \$(1)	Other Annual Compensation \$(2)	Awards		Payouts	
					Restricted Stock Award(s) \$(3)	Securities Underlying Options/SARs (# of Shares)	LTIP Payouts \$(4)	All Other Compensation \$(5)
Robert D. Glynn, Jr. Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation; Chairman of the Board of Pacific Gas and Electric Company	2003	\$1,050,000	\$ 0	\$3,154,268	\$2,169,950	486,000	\$9,879,911	\$ 666,050
	2002	1,050,000	787,500	4,833,389	0	150,000	632,461	79,777
	2001	900,000	1,181,700	4,817	3,000,000	470,800	74,588	413,196
Peter A. Darbee Senior Vice President and Chief Financial Officer of PG&E Corporation	2003	\$ 490,000	\$ 0	\$ 2,368	\$ 678,269	101,300	\$4,023,098	\$ 329,140
	2002	490,000	220,500	4,862	0	0	115,244	62,355
	2001	455,000	328,578	4,817	1,125,000	183,800	26,105	613,596
Bruce R. Worthington Senior Vice President and General Counsel of PG&E Corporation	2003	\$ 425,000	\$ 0	\$ 836,295	\$ 530,708	79,300	\$2,310,713	\$ 306,575
	2002	425,000	175,313	1,220,913	0	0	205,801	43,893
	2001	400,000	288,860	4,817	625,000	145,000	24,617	171,353
G. Brent Stanley Senior Vice President — Human Resources of PG&E Corporation	2003	\$ 305,000	\$ 0	\$ 2,368	\$ 353,927	52,900	\$2,141,176	\$ 204,782
	2002	305,000	114,375	4,862	0	0	84,311	18,010
	2001	285,000	187,103	4,817	625,000	102,800	15,385	110,691
P. Chrisman Iribe Senior Vice President of PG&E Corporation; Executive Vice President of National Energy & Gas Transmission, Inc.	2003	\$ 450,000	\$ 0	\$ 0	\$ 471,903	70,400	\$3,017,831	\$ 151,934
	2002	450,000	93,163	0	0	0	94,863	75,620
	2001	425,000	306,914	0	1,125,000	186,400	25,355	57,846
Gordon R. Smith Senior Vice President of PG&E Corporation; President and Chief Executive Officer of Pacific Gas and Electric Company	2003	\$ 735,000	\$ 0	\$2,402,048	\$ 943,441	140,900	\$5,842,500	\$ 453,723
	2002	735,000	519,278	4,310,520	0	0	182,009	37,173
	2001	630,000	664,808	937	1,750,000	272,000	40,282	241,302
Thomas B. King Senior Vice President and Chief of Utility Operations of Pacific Gas and Electric Company (November 1, 2003) Senior Vice President of PG&E Corporation (January 1, 1999 - October 31, 2003)	2003	\$ 500,000	\$ 0	\$ 23,780	\$ 530,708	79,300	\$2,938,351	\$ 659,488
	2002	450,000	93,163	0	0	0	94,863	89,263
	2001	425,000	306,914	0	1,125,000	186,400	41,020	1,090,207

Name and Principal Position	Year	Annual Compensation			Long-Term Compensation			
		Salary (\$)	Bonus \$(1)	Other Annual Compensation \$(2)	Awards		Payouts	
					Restricted Stock Award(s) \$(3)	Securities Underlying Options/SARs (# of Shares)	LTIP Payouts \$(4)	All Other Compensation \$(5)
Gregory M. Rueger	2003	\$358,000	\$ 0	\$ 642,860	\$272,477	40,700	\$1,563,204	\$243,325
Senior Vice President —	2002	358,000	194,215	1,007,117	0	0	42,166	16,646
Generation and Chief Nuclear	2001	340,000	257,550	0	625,000	79,400	15,385	129,145
Officer of Pacific Gas and Electric Company								
Kent M. Harvey	2003	\$302,000	\$ 0	\$ 0	\$272,477	40,700	\$1,557,466	\$209,703
Senior Vice President,	2002	302,000	173,952	0	0	0	41,434	18,812
Chief Financial Officer, and	2001	285,000	213,465	0	625,000	76,000	15,385	113,462
Treasurer of Pacific Gas and Electric Company								
Roger J. Peters	2003	\$302,000	\$ 0	\$ 0	\$272,477	40,700	\$1,557,466	\$204,502
Senior Vice President and	2002	302,000	166,402	0	0	0	41,434	19,385
General Counsel of Pacific Gas and Electric Company	2001	285,000	212,753	0	625,000	76,000	15,385	112,619
James K. Randolph	2003	\$337,000	\$ 0	\$ 669,741	\$265,537	39,700	\$1,557,466	\$233,943
Senior Vice President and	2002	337,000	165,130	1,282,378	0	0	41,434	15,602
Chief of Utility Operations of Pacific Gas and Electric Company (retired October 31, 2003)	2001	325,000	218,725	0	625,000	72,600	15,385	123,028

- (1) Represents payments received or deferred in 2003 and 2002 for achievement of corporate and organizational objectives in 2002 and 2001, respectively, under the Short-Term Incentive Plan. No decision has been made with respect to the 2003 Short-Term Incentive Plan.
- (2) Amounts reported consist of (i) reportable officer perquisite allowances and, for 2002 and 2003, amounts for non-business related travel (Mr. Glynn \$35,000 and \$62,998, respectively), (ii) payments of related taxes, and (iii) for 2002 and 2003, the cost of annuities to replace existing retirement benefits, at the time they are due under the Supplemental Executive Retirement Plan (SERP). The annuities will not change the after-tax benefits that would have been provided upon retirement under the existing arrangements. The cost of the annuity and associated tax restoration payments during 2003 for retirement obligations as of December 31, 2002, are: Mr. Glynn \$3,048,972, Mr. Worthington \$833,927, Mr. Smith \$2,402,048, Mr. Rueger \$642,860, and Mr. Randolph \$669,741.
- (3) As of the end of the year, the aggregate number of shares or units of restricted stock held by each named executive officer, and the value using the year-end closing price of a share of PG&E Corporation common stock, were: Mr. Glynn 148,525 (with a value of \$4,124,539), Mr. Darbee 46,425 (with a value of \$1,289,222), Mr. Worthington 36,325 (with a value of \$1,008,745), Mr. Stanley 24,225 (with a value of \$672,728), Mr. Iribe 32,300 (with a value of \$896,971), Mr. Smith 64,575 (with a value of \$1,793,248), Mr. King 36,325 (with a value of \$1,008,745), Mr. Rueger 18,650 (with a value of \$517,911), Mr. Harvey 18,650 (with a value of \$517,911), Mr. Peters 18,650 (with a value of \$517,911), and Mr. Randolph 18,175 (with a value of \$504,720). The restrictions lapse in annual increments of up to 25 percent on the first business day of 2004, 2005, 2006, and 2007, subject to the recipient's continued employment. In general, 20 percent of each year's increment is subject to forfeiture if PG&E Corporation fails to be in the top quartile of the comparator group as measured by relative annual total shareholder return at the end of the prior year. With respect to the Chairman, Chief Executive Officer, and President of PG&E Corporation, 25 percent of each year's increment is subject to forfeiture if PG&E Corporation fails to be in the top quartile of the comparator group as measured by total shareholder return at the end of the prior year, and an additional 25 percent is subject to forfeiture if PG&E Corporation fails to be in the top half of the comparator group. The shares of restricted stock have the same dividend rights as unrestricted shares of PG&E Corporation common stock.
- (4) Represents (i) payments received or deferred in 2004, 2003, and 2002 for achievement of corporate performance objectives for the periods 2001 through 2003, 2000 through 2002, and 1999 through 2001,

respectively, under the Performance Unit Plan (Mr. Glynn \$1,292,837, Mr. Darbee \$669,876, Mr. Worthington \$522,915, Mr. Stanley \$325,427, Mr. Iribe \$533,063, Mr. Smith \$799,143, Mr. King \$533,063, Mr. Rueger \$234,201, Mr. Harvey \$228,463, Mr. Peters \$228,463, and Mr. Randolph \$228,463), (ii) common stock equivalents called Special Incentive Stock Ownership Premiums (SISOPs) earned by executive officers under the Executive Stock Ownership Program and vested during 2003, and additional common stock equivalents reflecting dividends accrued on those SISOPs as follows: Mr. Glynn 2,948 (with a value of \$42,453), Mr. Darbee 10,346 (with a value of \$148,981), Mr. Worthington 533 (with a value of \$7,672), Mr. Stanley 2,474 (with a value of \$35,623), Mr. Iribe 6,430 (with a value of \$92,591), Mr. Smith 4,096 (with a value of \$58,989), and Mr. King 910 (with a value of \$13,111), and (iii) amounts representing one-half of the phantom restricted stock units granted in 2001 under the Senior Executive Retention Program that were subject to a performance measure (Mr. Glynn 307,692.5 units with a value of \$8,544,621, Mr. Darbee 115,385 units with a value of \$3,204,241, Mr. Worthington 64,102.5 units with a value of \$1,780,126, Mr. Stanley 64,102.5 units with a value of \$1,780,126, Mr. Iribe 86,142.5 units with a value of \$2,392,177, Mr. Smith 179,487.5 units with a value of \$4,984,368, Mr. King 86,142.5 units with a value of \$2,392,177, Mr. Rueger 47,857.5 units with a value of \$1,329,003, Mr. Harvey 47,857.5 units with a value of \$1,329,003, Mr. Peters 47,857.5 units with a value of \$1,329,003, and Mr. Randolph 47,857.5 units with a value of \$1,329,003). The value of all phantom restricted units granted under the Senior Executive Retention Program is based solely on the closing price of PG&E Corporation common stock on the date that the units vested, December 31, 2003. As previously reported, the total number of phantom restricted stock units granted under the Program and their value as of their vesting date of December 31, 2003, inclusive of the performance-based units described above, were: Mr. Glynn 615,385 units with a value of \$17,089,241, Mr. Darbee 230,770 units with a value of \$6,408,483, Mr. Worthington 128,205 units with a value of \$3,560,253, Mr. Stanley 128,205 units with a value of \$3,560,253, Mr. Iribe 172,285 units with a value of \$4,784,354, Mr. Smith 358,975 units with a value of \$9,968,736, Mr. King 172,285 units with a value of \$4,784,354, Mr. Rueger 95,715 units with a value of \$2,658,006, Mr. Harvey 95,715 units with a value of \$2,658,006, Mr. Peters 95,715 units with a value of \$2,658,006, and Mr. Randolph 95,715 units with a value of \$2,658,006.

- (5) Amounts reported for 2003 consist of: (i) contributions to defined contribution retirement plans (Mr. Glynn \$9,000, Mr. Darbee \$16,125, Mr. Worthington \$3,953, Mr. Stanley \$3,853, Mr. Iribe \$20,000, Mr. Smith \$9,000, Mr. King \$20,000, Mr. Rueger \$9,000, Mr. Harvey \$9,000, Mr. Peters \$9,000, and Mr. Randolph \$9,000), (ii) contributions received or deferred under excess benefit arrangements associated with defined contribution retirement plans (Mr. Glynn \$38,250, Mr. Darbee \$5,925, Mr. Worthington \$15,172, Mr. Stanley \$9,872, Mr. Iribe \$25,000, Mr. Smith \$24,075, Mr. King \$2,500, Mr. Rueger \$7,110, Mr. Harvey \$4,590, Mr. Peters \$4,590, and Mr. Randolph \$6,165), (iii) above-market interest on deferred compensation (Mr. Glynn \$18,800, Mr. Darbee \$3,757, Mr. Worthington \$350, Mr. Stanley \$1,057, Mr. Iribe \$203, Mr. Smith \$648, Mr. King \$1,285, Mr. Rueger \$548, Mr. Harvey \$306, Mr. Peters \$331, and Mr. Randolph \$167), (iv) relocation allowances and other one-time payments, Mr. King \$374,645, (v) sale of vacation (Mr. Worthington \$20,433, Mr. Iribe \$69,231, Mr. King \$36,058, Mr. Harvey \$5,807, Mr. Peters \$581, and Mr. Randolph \$1,944), and (vi) amounts received pursuant to management retention programs (Mr. Glynn \$600,000, Mr. Darbee \$303,333, Mr. Worthington \$266,667, Mr. Stanley \$190,000, Mr. Iribe \$37,500, Mr. Smith \$420,000, Mr. King \$225,000, Mr. Rueger \$226,667, Mr. Harvey \$190,000, Mr. Peters \$190,000, and Mr. Randolph \$216,667).

Option/SAR Grants in 2003

This table summarizes the distribution and the terms and conditions of stock options granted to the executive officers named in the Summary Compensation Table during the past year.

Name	Individual Grants				Grant Date Value
	Number of Securities Underlying Options/SARs Granted (#)(1)(2)	% of Total Options/SARs Granted to Employees in 2003(2)	Exercise or Base Price (\$/Sh)(3)	Expiration Date(4)	Grant Date Present Value (\$)(5)
Robert D. Glynn, Jr.	486,000	13.32%	14.61	01-03-2013	\$2,760,480
Peter A. Darbee	101,300	2.78%	14.61	01-03-2013	575,384
Bruce R. Worthington	79,300	2.17%	14.61	01-03-2013	450,424
G. Brent Stanley	52,900	1.45%	14.61	01-03-2013	300,472
P. Chrisman Iribe	70,400	1.93%	14.61	01-03-2013	399,872
Gordon R. Smith	140,900	3.86%	14.61	01-03-2013	800,312
Thomas B. King	79,300	2.17%	14.61	01-03-2013	450,424
Gregory M. Rueger	40,700	1.12%	14.61	01-03-2013	231,176
Kent M. Harvey	40,700	1.12%	14.61	01-03-2013	231,176
Roger J. Peters	40,700	1.12%	14.61	01-03-2013	231,176
James K. Randolph	39,700	1.09%	14.61	01-03-2013	225,496

- (1) All options granted to executive officers in 2003 are exercisable as follows: 25 percent of the options may be exercised on or after the first anniversary of the date of grant, 50 percent on or after the second anniversary, 75 percent on or after the third anniversary, and 100 percent on or after the fourth anniversary, provided that options will vest immediately upon the occurrence of certain events. No options were accompanied by tandem dividend equivalents.
- (2) No stock appreciation rights (SARs) have been granted since 1991.
- (3) The exercise price is equal to the closing price of PG&E Corporation common stock on the date of grant.
- (4) All options granted to executive officers in 2003 expire ten years and one day from the date of grant, subject to earlier expiration in the event of the officer's termination of employment with PG&E Corporation, the Utility, or one of their respective subsidiaries.
- (5) Estimated present values are based on the Black-Scholes Model, a mathematical formula used to value options traded on stock exchanges. The Black-Scholes Model considers a number of factors, including the expected volatility and dividend rate of the stock, interest rates, and time of exercise of the option. The following assumptions were used in applying the Black-Scholes Model to the 2003 option grant shown in the table above: volatility of 45.0 percent, risk-free rate of return of 3.94 percent, dividend yield of \$0.00 (the annual dividend rate on the grant date), and an exercise date ten years after the date of grant. The ultimate value of the options will depend on the future market price of PG&E Corporation common stock, which cannot be forecast with reasonable accuracy. That value will depend on the future success achieved by employees for the benefit of all shareholders. The estimated grant date present value for the options shown in the table was \$5.68 per share.

Aggregated Option/SAR Exercises in 2003 and Year-End Option/SAR Values

This table summarizes exercises of stock options and tandem stock appreciation rights (granted in prior years) by the executive officers named in the Summary Compensation Table during the past year, as well as the number and value of all unexercised options held by such named executive officers at the end of 2003.

Name	Shares Acquired on Exercise (#)	Value Realized (\$)	Number of Securities Underlying Unexercised Options/SARs at End of 2003 (#) (Exercisable/ Unexercisable)	Value of Unexercised In-the-Money Options/SARs at End of 2003 (\$)(1) (Exercisable/ Unexercisable)
Robert D. Glynn, Jr.	0	0	1,363,492/1,057,232	\$5,306,585/\$12,720,407
Peter A. Darbee	0	0	309,402/272,898	\$ 1,608,109/\$3,371,912
Bruce R. Worthington	0	0	369,268/215,232	\$ 1,633,980/\$2,656,447
G. Brent Stanley	0	0	204,902/149,798	\$ 1,069,201/\$1,843,813
P. Chrisman Iribe	31,000	323,537	315,034/235,566	\$ 1,203,811/\$2,923,614
Gordon R. Smith	0	0	612,302/393,098	\$ 2,824,560/\$4,857,529
Thomas B. King	0	0	293,934/244,466	\$ 1,486,781/\$3,040,738
Gregory M. Rueger	82,402	210,363	135,132/113,598	\$ 139,168/\$1,406,559
Kent M. Harvey	31,334	378,715	151,734/111,332	\$ 359,225/\$1,376,076
Roger J. Peters(2)	2,000	\$ (12,740)	183,568/111,332	\$ 736,723/\$1,376,076
James K. Randolph(2)	4,500	\$ (30,375)	189,267/108,066	\$ 773,373/\$1,332,432

- (1) Based on the difference between the option exercise price (without reduction for the amount of accrued dividend equivalents, if any) and a fair market value of \$27.77, which was the closing price of PG&E Corporation common stock on December 31, 2003.
- (2) The options exercised would have expired on January 4, 2004. After accounting for accrued dividend equivalents, Mr. Peters realized \$8,240 and Mr. Randolph realized \$16,830.

Long-Term Incentive Program — Awards in 2003

This table summarizes the long-term incentive grants made to the executive officers named in the Summary Compensation Table during the past year.

Name	Awards	
	Number of Shares, Units, or Other Rights	Performance or Other Period Until Maturity or Payout
Gregory M. Rueger	2,601(1)	3 years
Kent M. Harvey	3,915(1)	3 years
Roger J. Peters	631(1)	3 years
James K. Randolph	177(1)	3 years

- (1) Represents common stock equivalents called Special Incentive Stock Ownership Premiums (SISOPs) earned under the Executive Stock Ownership Program. SISOPs are earned by eligible officers who achieve and maintain minimum PG&E Corporation common stock ownership levels as set by the Nominating, Compensation, and Governance Committee. All of the officers named in the Summary Compensation Table are eligible officers. Each SISOP represents a share of PG&E Corporation common stock that vests at the end of three years. Units can be forfeited prior to vesting if an eligible officer fails to maintain his or her minimum stock ownership level. Upon retirement or termination, vested SISOPs are distributed in the form of an equivalent number of shares of PG&E Corporation common stock.

Retirement Benefits

PG&E Corporation and the Utility provide retirement benefits to some of the executive officers named in the Summary Compensation Table. The benefit formula for eligible executive officers is 1.7 percent of the average of the three highest combined salary and annual Short-Term Incentive Plan payments during the last ten years of service multiplied by years of credited service. During 2002 and 2003, annuities were purchased to replace a significant portion of the unfunded retirement benefits for certain officers whose entire accrued benefit could not be provided under the Retirement Plan due to tax code limits. The annuities will not change the amount or timing of the after-tax benefits that would have been provided upon retirement under the Supplemental Executive Retirement Plan (SERP) or similar arrangements. In connection with the annuities, tax restoration payments were made such that the annuitization was tax-neutral to the executive officer. Effective July 1, 2003, Mr. Darbee and Mr. King became participants in the SERP with five years of credited service. Mr. Darbee and Mr. King will each earn an additional five years of credited service provided that they are employed by PG&E Corporation or a subsidiary on July 1, 2008. As of December 31, 2003, the estimated pre-tax annual retirement benefits payable under the SERP or similar arrangements (assuming credited service to age 65), adjusted to reflect the effect of the annuities, for the most highly compensated executive officers were as follows: Mr. Glynn \$309,602, Mr. Darbee \$286,570, Mr. Worthington \$285,740, Mr. Stanley \$117,610, Mr. Smith \$430,326, Mr. King \$421,200, Mr. Rueger \$287,450, Mr. Harvey \$330,436, Mr. Peters \$306,808, and Mr. Randolph \$220,617. The estimated annual retirement benefits are single life annuity benefits and would not be subject to any Social Security offsets.

Termination of Employment and Change in Control Provisions

The PG&E Corporation Officer Severance Policy, which covers most officers of PG&E Corporation and its subsidiaries, including the executive officers named in the Summary Compensation Table, provides benefits if a covered officer is terminated without cause. In most situations, benefits under the policy include (1) a lump sum payment of one and one-half or two times annual base salary and Short-Term Incentive Plan target (the applicable severance multiple being dependent on an officer's level), (2) continued vesting of equity-based incentives for 18 months or two years after termination (depending on the applicable severance multiple), (3) accelerated vesting of up to two-thirds of the common stock equivalents granted under the Executive Stock Ownership Program (depending on an officer's level), and (4) payment of health care insurance premiums for 18 months or two years after termination (depending on the applicable severance multiple). In lieu of all or a portion of the lump sum payment, a terminated officer who is covered by PG&E Corporation's Supplemental Executive Retirement Plan can elect additional years of service and/or age for purposes of calculating pension benefits. Effective July 21, 1999, the policy was amended to provide covered officers with alternative benefits that apply upon actual or constructive termination following a change in control or potential change in control. For these purposes, "change in control" has the same definition as under the Long-Term Incentive Program (see below). Constructive termination includes certain changes to a covered officer's responsibilities. In the event of a change in control or potential change in control, the policy provides for a lump sum payment of the total of (1) unpaid base salary earned through the termination date, (2) Short-Term Incentive Plan target calculated for the fiscal year in which termination occurs (Target Bonus), (3) any accrued but unpaid vacation pay, and (4) three times the sum of Target Bonus and the officer's annual base salary in effect immediately before either the date of termination or the change in control, whichever base salary is greater. Change in control termination benefits also include reimbursement of excise taxes levied upon the severance benefit pursuant to Internal Revenue Code Section 4999.

The Long-Term Incentive Program (LTIP) permits the grant of various types of stock-based incentives, including performance shares, stock options, restricted stock, performance units, and incentives granted under the Non-Employee Director Stock Incentive Plan. The LTIP and the component plans provide that, upon the occurrence of a change in control, (1) any time periods relating to the exercise or realization of any incentive (including common stock equivalents granted under the Executive Stock Ownership Program) will be accelerated so that such incentive may be exercised or realized in full immediately upon the change in control, (2) all shares of restricted stock will immediately cease to be forfeitable, and (3) all conditions relating to the realization of any stock-based incentive will terminate immediately. Under the LTIP, a "change in control"

will be deemed to have occurred if any of the following occurs: (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 PG&E Corporation representing 20 percent or more of the combined voting power of PG&E Corporation’s then outstanding securities, (2) 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 the Corporation, of each new director was approved by a vote of at least two-thirds of the directors then still in office who were directors at the beginning of the period, or (3) the shareholders of the Corporation shall have approved (i) any consolidation or merger of the Corporation other than a merger or consolidation that 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 definition, the term “combined voting power” means the combined voting power of the then outstanding voting securities of the Corporation or the other relevant entity.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

Security Ownership of Management

The following table sets forth the number of shares of PG&E Corporation common stock beneficially owned (as defined in the rules of the Securities and Exchange Commission) as of January 31, 2004, by the respective directors of PG&E Corporation and the Utility, the executive officers of PG&E Corporation and the Utility named in the Summary Compensation Table, and all directors and executive officers of PG&E Corporation and the Utility as a group. As of January 31, 2004, no director, nominee for director, or executive officer owned shares of any class of the Utility’s securities. The table also sets forth common stock equivalents credited to the accounts of directors and executive officers under PG&E Corporation’s deferred compensation and equity plans.

Name	Beneficial Stock Ownership(1)(2)(3)	Percent of Class(4)	Common Stock Equivalents(5)	Total
David R. Andrews(6)	4,054	*	767	4,821
Leslie S. Biller(6)	1,051	*	4,083	5,134
David A. Coulter(6)	5,681	*	22,897	28,578
C. Lee Cox(6)	47,207	*	3,609	50,816
William S. Davila(6)	21,517	*	12,949	34,466
Robert D. Glynn, Jr.(7)	1,901,961	*	99,181	2,001,142
David M. Lawrence, MD(6)	45,197	*	3,041	48,238
Mary S. Metz(6)	24,276	*	4,366	28,642
Carl E. Reichardt(6)	26,197	*	14,335	40,532
Gordon R. Smith(8)	804,073	*	20,059	824,132
Barry Lawson Williams(6)	22,109	*	5,689	27,798
Peter A. Darbee(9)	437,150	*	10,346	447,496
Bruce R. Worthington(9)	416,605	*	7,917	424,522
G. Brent Stanley(9)	289,592	*	4,262	293,854
P. Chrisman Iribe(9)	428,890	*	99,008	527,898
Thomas B. King(10)	435,614	*	49,366	484,980

Name	Beneficial Stock Ownership(1)(2)(3)	Percent of Class(4)	Common Stock Equivalents(5)	Total
Gregory M. Rueger(10)	227,225	*	0	227,225
Kent M. Harvey(10)	138,918	*	0	138,918
Roger J. Peters(10)	262,930	*	86,144	349,074
James K. Randolph(11)	268,569	*	141	268,710
All PG&E Corporation directors and executive officers as a group (16 persons)	4,436,002	1.1	227,291	4,663,293
All Pacific Gas and Electric Company directors and executive officers as a group (16 persons)	4,192,772	1.1	328,184	4,520,956

* Less than 1 percent

- (1) Includes any shares held in the name of the spouse, minor children, or other relatives sharing the home of the director or executive officer and, in the case of executive officers, includes shares of PG&E Corporation common stock held in the defined contribution retirement plans maintained by PG&E Corporation, Pacific Gas and Electric Company, and their respective subsidiaries. Except as otherwise indicated below, the directors, nominees for director, and executive officers have sole voting and investment power over the shares shown. Voting power includes the power to direct the voting of the shares held, and investment power includes the power to direct the disposition of the shares held.

Also includes the following shares of PG&E Corporation common stock in which the beneficial owners share voting and investment power: Mr. Andrews 2,076 shares, Mr. Biller 1,051 shares, Mr. Coulter 5,681 shares, Mr. Cox 24,192 shares, Mr. Davila 200 shares, Dr. Lawrence 15,676 shares, Dr. Metz 7,681 shares, Mr. Smith 3,884 shares, Mr. Darbee 69,818, Mr. Worthington 2,288 shares, Mr. Rueger 13,987 shares, Mr. Peters 184 shares, all PG&E Corporation directors and executive officers as a group 132,547 shares, and all Pacific Gas and Electric Company directors and executive officers as a group 74,612 shares.

- (2) Includes shares of PG&E Corporation common stock which the directors and executive officers have the right to acquire within 60 days of January 31, 2004, through the exercise of vested stock options granted under the PG&E Corporation Long-Term Incentive Program, as follows: Mr. Andrews 1,978 shares, Mr. Cox 23,015 shares, Mr. Glynn 1,713,325 shares, Dr. Lawrence 23,015 shares, Dr. Metz 14,368 shares, Mr. Reichardt 20,141 shares, Mr. Smith 702,392 shares, Mr. Williams 16,254 shares, Mr. Darbee 353,159 shares, Mr. Iribe 404,601 shares, Mr. Stanley 263,626 shares, Mr. Worthington 374,701 shares, Mr. King 385,726 shares, Mr. Rueger 178,506 shares, Mr. Harvey 97,300 shares, Mr. Peters 226,376 shares, Mr. Randolph 231,258 shares, all PG&E Corporation directors and executive officers as a group 3,845,092 shares, and all Pacific Gas and Electric Company directors and executive officers as a group 3,589,855 shares. The directors and executive officers have neither voting power nor investment power with respect to shares shown unless and until such shares are purchased through the exercise of the options, pursuant to the terms of the PG&E Corporation Long-Term Incentive Program.
- (3) Includes restricted shares of PG&E Corporation common stock awarded under the PG&E Corporation Long-Term Incentive Program. As of January 31, 2004, directors and executive officers of PG&E Corporation and Pacific Gas and Electric Company held the following numbers of restricted shares that may not be sold or otherwise transferred until certain vesting conditions are satisfied: Mr. Andrews 2,076 shares, Mr. Biller 1,051 shares, Mr. Coulter 3,703 shares, Mr. Cox 3,703 shares, Mr. Davila 4,056 shares, Mr. Glynn 163,393 shares, Dr. Lawrence 4,056 shares, Dr. Metz 4,056 shares, Mr. Reichardt 4,056 shares, Mr. Smith 70,321 shares, Mr. Williams 4,056 shares, Mr. Darbee 48,498 shares, Mr. Iribe 24,225 shares, Mr. Stanley 25,008 shares, Mr. Worthington 39,553 shares, Mr. King 39,553 shares, Mr. Rueger 18,777 shares, Mr. Harvey 19,797 shares, Mr. Peters 19,797 shares, Mr. Randolph 13,631 shares, all PG&E Corporation directors and executive officers as a group 417,498 shares, and all Pacific Gas and Electric Company directors and executive officers as a group 381,892 shares.

- (4) The percent of class calculation is based on the number of shares of PG&E Corporation common stock outstanding as of January 31, 2004, excluding shares held by a subsidiary.
- (5) Reflects the number of stock units purchased by directors and executive officers through salary and other compensation deferrals or awarded under equity compensation plans. The value of each stock unit is equal to the value of a share of PG&E Corporation common stock and fluctuates daily based on the market price of PG&E Corporation common stock. The directors and officers who own these stock units share the same market risk as PG&E Corporation shareholders, although they do not have voting rights with respect to these stock units.
- (6) Mr. Andrews, Mr. Biller, Mr. Coulter, Mr. Cox, Mr. Davila, Dr. Lawrence, Dr. Metz, Mr. Reichardt, and Mr. Williams are directors of both PG&E Corporation and Pacific Gas and Electric Company.
- (7) Mr. Glynn is a director and executive officer of PG&E Corporation, and also is a director of Pacific Gas and Electric Company. He is named in the Summary Compensation Table.
- (8) Mr. Smith is a director and an executive officer of Pacific Gas and Electric Company, and also is an executive officer of PG&E Corporation. He is named in the Summary Compensation Table.
- (9) Mr. Darbee, Mr. Iribe, Mr. Stanley, and Mr. Worthington are executive officers of PG&E Corporation named in the Summary Compensation Table.
- (10) Mr. Harvey, Mr. King, Mr. Peters, and Mr. Rueger are executive officers of Pacific Gas and Electric Company named in the Summary Compensation Table.
- (11) Mr. Randolph retired as an executive officer of Pacific Gas and Electric Company in 2003. He is named in the Summary Compensation Table.

Principal Shareholders

The following table presents certain information regarding shareholders that PG&E Corporation and the Utility know are the beneficial owners of more than 5 percent of any class of voting securities of PG&E Corporation or the Utility as of January 31, 2004:

Class of Stock	Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership	Percent of Class
Pacific Gas and Electric Company stock(1)	PG&E Corporation(2) One Market, Spear Tower, Suite 2400 San Francisco, CA 94105	321,314,760	94.90%
PG&E Corporation Common stock	State Street Bank and Trust Company(3) 225 Franklin Street Boston, MA 02110	31,626,606	8.01%

- (1) Pacific Gas and Electric Company's common stock and preferred stock vote together as a single class. Each share is entitled to one vote.
- (2) As a result of the formation of the holding company on January 1, 1997, PG&E Corporation became the holder of all issued and outstanding shares of Pacific Gas and Electric Company common stock. As of January 31, 2004, PG&E Corporation and a subsidiary held 100 percent of the issued and outstanding shares of Pacific Gas and Electric Company common stock, and neither PG&E Corporation nor any of its subsidiaries held shares of Pacific Gas and Electric Company preferred stock.
- (3) The information relating to State Street Bank and Trust Company is based on beneficial ownership as of December 31, 2003, as reported in a Schedule 13G, dated February 5, 2004, filed with the Securities and Exchange Commission. The bank held 19,204,598 shares in its capacity as Trustee of the Pacific Gas and Electric Company Savings Fund Plan. The Trustee may not vote these shares in the absence of voting instructions from the Plan participants. The bank also held 12,422,008 shares of PG&E Corporation common stock in various other fiduciary capacities. The bank has sole voting power with respect to 11,500,089 of these shares, shared voting power with respect to 13,495 of these shares, sole investment

power with respect to 12,386,522 of these shares, and shared investment power with respect to 31,486 of these shares.

Equity Compensation Plan Information

The following table provides information as of December 31, 2003, 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	27,541,6291	\$21.26	12,572,096(1)
Equity compensation plans not approved by shareholders	—	\$ —	—
Total equity compensation plans	27,541,629	\$21.26	12,572,096

- (1) Represents the total number of shares available for issuance under PG&E Corporation's Long-Term Incentive Program (LTIP) as of December 31, 2003. Outstanding stock-based awards granted under the LTIP include stock options, restricted stock, performance shares, 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 14 to the Consolidated Financial Statements.

Item 13. Certain Relationships and Related Transactions.

Not applicable.

Item 14. Principal Accountant Fees and Services

Fees Paid to Independent Public Accountants

The Audit Committees have reviewed the audit and non-audit fees that PG&E Corporation, Pacific Gas and Electric Company, and their respective subsidiaries have paid to the independent public accountants for purposes of considering whether such fees are compatible with maintaining the auditor's independence.

Audit Fees. Estimated fees billed for services rendered by Deloitte & Touche LLP for the reviews of Forms 10-Q and for the audits of the financial statements of PG&E Corporation and its subsidiaries were \$9.8 million for 2002 and \$6.5 million for 2003. These amounts include fees for stand-alone audits of various subsidiaries, including estimated fees of \$4.4 million for 2002 and \$2.8 million for 2003 for Pacific Gas and Electric Company and its subsidiaries.

Audit-Related Fees. Aggregate fees billed for all audit-related services rendered by Deloitte & Touche LLP to PG&E Corporation and its subsidiaries consisted of \$0.9 million of fees in 2002 and \$0.7 million of fees for 2003. These amounts include \$206,000 of audit-related fees in 2002 and \$351,000 of audit-related fees in 2003 for Pacific Gas and Electric Company and its subsidiaries. Specific services for both PG&E Corporation and its subsidiaries and Pacific Gas and Electric Company and its subsidiaries in both years include employee benefit plan audits, consultations on financial accounting and reporting standards, a required transition property procedures report, and nuclear decommissioning trust audits. Amounts in 2003 also include Sarbanes-Oxley Section 404 readiness work.

Tax Fees. Aggregate fees billed for permissible tax services rendered by Deloitte & Touche LLP to PG&E Corporation and its subsidiaries consisted of \$2.2 million of fees during 2002 and \$1.1 million of fees during 2003. These amounts for 2002 include \$4,000 for Pacific Gas and Electric Company and its subsidiaries. Specific services in both years include services to support IRS audit appeals and questions, tax

strategy services, and review of tax returns. Amounts in 2002 also include a review of a private letter ruling request.

All Other Fees. Aggregate fees billed for all other services rendered by Deloitte & Touche LLP to PG&E Corporation and its subsidiaries consisted of \$1.1 million in 2002. These services were consulting services for the implementation of risk management software. None of these services were for Pacific Gas and Electric Company. No such services were rendered in 2003.

Pre-Approval of Services Provided by the Independent Public Accountant

As of June 2002, PG&E Corporation and its controlled subsidiaries have entered into new engagements with Deloitte & Touche LLP and its affiliate, Deloitte Consulting, only for audit services, audit-related services, or tax services, which Deloitte & Touche LLP and its affiliates may provide to Deloitte & Touche LLP's audit clients under the Sarbanes-Oxley Act of 2002. PG&E Corporation and its subsidiaries traditionally have obtained these types of services from its independent public accountants.

Since November 2002, the Audit Committees have been responsible for pre-approving all audit and non-audit services provided by Deloitte & Touche LLP to PG&E Corporation, Pacific Gas and Electric Company, or their controlled subsidiaries, pursuant to Committee pre-approval procedures that are reviewed and amended from time to time. At the beginning of each fiscal year, the PG&E Corporation and Pacific Gas and Electric Company Audit Committees approve the selection of the independent public accountants for that fiscal year, and approve obtaining from the auditors a detailed list of (1) audit services, (2) audit-related services, and (3) tax services, up to specified fee amounts. "*Audit services*" generally includes audit and review of annual and quarterly financial statements and services that only the external auditors reasonably can provide (e.g., comfort letters, statutory audits, attest services, consents, and assistance with and review of documents filed with the Securities and Exchange Commission). "*Audit-related services*" generally include assurance and related services that traditionally are performed by the independent public accountants (e.g., employee benefit plan audits, due diligence related to mergers and acquisitions, accounting consultations and audits in connection with acquisitions, internal control reviews, and attest services that are not required by statute or regulation). "*Tax services*" generally includes compliance, tax strategy, tax appeals, and specialized tax issues, all of which also must be permissible under the Sarbanes-Oxley Act of 2002. In determining whether to pre-approve any services from the independent public accountants, the Audit Committees assess, among other things, the impact of that service on the auditor's independence.

Following the initial annual pre-approval, the Audit Committees must pre-approve any proposed engagement of the independent public accountants for any audit, audit-related, and tax services that are not included on the list of pre-approved services, and must pre-approve any listed pre-approved services that would cause PG&E Corporation or Pacific and Electric Company to exceed the authorized fee amounts. Other services may be obtained from the independent public accountants only following review and approval from the applicable company's management and review and pre-approval by the applicable Audit Committee.

Each Audit Committee has delegated to one or more members of the Committee the authority to pre-approve audit and non-audit services provided by the respective company's independent public accountants. Any pre-approvals granted pursuant to this authority must be presented to the full Audit Committee at the next regularly scheduled Committee meeting. No such pre-approvals were granted for 2003.

At each regular meeting of the Audit Committees, management reports the specific non-audit services being performed by Deloitte & Touche LLP for the respective company and its subsidiaries, the dollar amounts associated with these services, and a comparison of fees paid to date to the pre-approved amounts.

During 2003, all services provided by Deloitte & Touche LLP to PG&E Corporation, Pacific Gas and Electric Company, and their consolidated affiliates were approved pursuant to the applicable pre-approval procedures.

Item 15. Exhibits, Financial Statement Schedules, and Reports on Form 8-K.

(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 2003 Annual Report, which have been incorporated by reference in this report:

Consolidated Statements of Operations for the Years Ended December 31, 2003, 2002, and 2001, for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2003, and 2002 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Common Shareholders' Equity for the Years Ended December 31, 2003, 2002, and 2001, for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2003, 2002, and 2001 for Pacific Gas and Electric Company.

Notes to Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Independent Auditors' Report (Deloitte & Touche LLP).

2. Independent Auditors' Report (Deloitte & Touche LLP) included at page 77 of this Form 10-K.

3. Financial statement schedules:

I — Condensed Financial Information of Parent as of December 31, 2003 and 2002 and for the Years Ended December 31, 2003, 2002, and 2001.

II — Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 2003, 2002, and 2001.

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
3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 5, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (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 February 18, 2004
3.4	Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of May 6, 1998 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-2348), Exhibit 3.1)
3.5	Bylaws of Pacific Gas and Electric Company amended as of February 18, 2004

Exhibit Number	Exhibit Description
4.1	First and Refunding Mortgage of Pacific Gas and Electric Company dated December 1, 1920, and supplements thereto dated April 23, 1925, October 1, 1931, March 1, 1941, September 1, 1947, May 15, 1950, May 1, 1954, May 21, 1958, November 1, 1964, July 1, 1965, July 1, 1969, January 1, 1975, June 1, 1979, August 1, 1983, and December 1, 1988 (incorporated by reference to Registration No. 2-1324, Exhibits B-1, B-2, and B-3; Registration No. 2-4676, Exhibit B-22; Registration No. 2-7203, Exhibit B-23; Registration No. 2-8475, Exhibit B-24; Registration No. 2-10874, Exhibit 4B; Registration No. 2-14144, Exhibit 4B; Registration No. 2-22910, Exhibit 2B; Registration No. 2-23759, Exhibit 2B; Registration No. 2-35106, Exhibit 2B; Registration No. 2-54302, Exhibit 2C; Registration No. 2-64313, Exhibit 2C; Registration No. 2-86849, Exhibit 4.3; and Pacific Gas and Electric Company's Form 8-K dated January 18, 1989 (File No. 1-2348), Exhibit 4.2)
4.2	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).
4.3	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 Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1)
4.4	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).
4.5	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 Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.2)
4.6	Form of Rights Agreement dated as of December 22, 2000, between PG&E Corporation and Mellon Investor Services LLC, including the Form of Rights Certificate as Exhibit A, the Summary of Rights to Purchase Preferred Stock as Exhibit B, and the Form of Certificate of Determination of Preferences for the Preferred Stock as Exhibit C (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 4.2)
4.7	Amendment to Rights Agreement dated February 18, 2004, between PG&E Corporation and Mellon Investor Services LLC (incorporated by reference to PG&E Corporation's Form 8-K filed February 19, 2004 (File No. 1-12609), Exhibit 99)
4.8	Indenture dated as of July 2, 2003, by and between PG&E Corporation and Bank One, N.A. (incorporated by reference to PG&E Corporation's Form 8-K filed July 2, 2003 (File No. 1-12609), Exhibit 4.1)
4.9	Utility Stock Base Pledge Agreement dated as of July 2, 2003, by and among PG&E Corporation, Bank One, N.A. and Deutsche Bank Trust Company Americas (incorporated by reference to PG&E Corporation's Form 8-K filed July 2, 2003 (file No. 1-12609), Exhibit 4.2)
4.10	Utility Stock Protective Pledge Agreement dated as of July 2, 2003, by and among PG&E Corporation, Bank One, N.A. and Deutsche Bank Trust Company Americas (incorporated by reference to PG&E Corporation's Form 8-K filed July 2, 2003 (file No. 1-12609), Exhibit 4.3)
4.11	Form of 6 7/8 percent Senior Secured Note due 2008 (incorporated by reference to PG&E Corporation's Form 8-K filed July 2, 2003 (file No. 1-12609), Exhibit 4.4)

Exhibit Number	Exhibit Description
10.1	The Gas Accord Settlement Agreement, together with accompanying tables, adopted by the California Public Utilities Commission on August 1, 1997, in Decision 97-08-055 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 1997 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2), as amended by Operational Flow Order (OFO) Settlement Agreement, approved by the California Public Utilities Commission on February 17, 2000, in Decision 00-02-050, as amended by Comprehensive Gas OII Settlement Agreement, approved by the California Public Utilities Commission on May 18, 2000, in Decision 00-05-049 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10); and the Gas Accord II Settlement Agreement, approved by the California Public Utilities Commission on August 22, 2002, in Decision 01-09-016 (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 10.1)
10.2	Commitment Letter dated March 5, 2003, between PG&E Corporation and Lehman Brothers, Inc. (incorporated by reference to PG&E Corporation's Form 8-K filed March 6, 2003 (File No. 1-12609), Exhibit 99.2)
10.3	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)
10.4	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
10.5	Operating Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated July 9, 1996
10.6	PG&E Trans-User Agreement between Pacific Gas and Electric Company and PG&E Gas Transmission, Northwest Corporation dated November 15, 1999
10.7	Electronic Commerce System User Agreement between Pacific Gas and Electric Company and PG&E Gas Transmission, Northwest Corporation, effective as of September 28, 2001
10.8	Operating Agreement effective as of April 1, 2003, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348) Exhibit 10.1)
*10.9	PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2001 (File No. 1-12609), Exhibit 10.4)
*10.10	Agreement and Release between PG&E Corporation and Thomas G. Boren dated December 18, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.23)
*10.11	Description of Compensation Arrangement between PG&E Corporation and Peter Darbee (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.3)
*10.12	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)

Exhibit Number	Exhibit Description
*10.13	Letter regarding Compensation Arrangement between PG&E Corporation and Lyn E. Maddox dated April 25, 1997 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.7)
*10.14	Letter Regarding Relocation Arrangement Between PG&E Corporation and Thomas B. King dated March 16, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 10)
*10.15	Description of Relocation Arrangement Between PG&E Corporation and Lyn E. Maddox (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.9)
*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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609) Exhibit 10.3)
*10.17	Letter regarding Compensation Arrangement between PG&E Corporation and Peter A. Darbee effective June 18, 2003 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609) Exhibit 10.4)
*10.18	PG&E Corporation Senior Executive Officer Retention Program approved December 20, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10)
*10.19.1	Letter regarding retention award to Robert D. Glynn, Jr. dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.1)
*10.19.2	Letter regarding retention award to Gordon R. Smith dated January 22, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.2)
*10.19.3	Letter regarding retention award to Peter A. Darbee dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.3)
*10.19.4	Letter regarding retention award to Bruce R. Worthington dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.4)
*10.19.5	Letter regarding retention award to G. Brent Stanley dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.5)
*10.19.6	Letter regarding retention award to Daniel D. Richard, Jr. dated January 22, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.6)
*10.19.7	Letter regarding retention award to James K. Randolph dated February 27, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.7)
*10.19.8	Letter regarding retention award to Gregory M. Rueger dated February 27, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.8)
*10.19.9	Letter regarding retention award to Kent M. Harvey dated February 27, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.9)

Exhibit Number	Exhibit Description
*10.19.10	Letter regarding retention award to Roger J. Peters dated February 27, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.10)
*10.19.11	Letter regarding retention award to Lyn E. Maddox dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.12)
*10.19.12	Letter regarding retention award to P. Chrisman Iribe dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.13)
*10.19.13	Letter regarding retention award to Thomas B. King dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.14)
*10.20	Pacific Gas and Electric Company Management Retention Program (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609 and File No. 1-2348), Exhibit 10.1)
*10.21	PG&E Corporation Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.2)
*10.22	PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2)
*10.23	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2003 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.35)
*10.24	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2004
*10.25	Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended as of September 19, 2001 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2001 (File No. 1-2248), Exhibit 10.16)
*10.26.1	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)
*10.26.2	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)
*10.26.3	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)
*10.26.4	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)

Exhibit Number	Exhibit Description
*10.26.5	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)
*10.26.6	Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Thomas G. Boren 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 10.37.6)
*10.27.1	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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609); Exhibit 10.2.1)
*10.27.2	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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348); Exhibit 10.2.2)
*10.27.3	Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and James K. Randolph dated April 18, 2003 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348); Exhibit 10.2.3)
*10.27.4	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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348); Exhibit 10.2.4)
*10.27.5	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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609); Exhibit 10.2.5)
*10.28	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)
*10.29	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)
*10.30	PG&E Corporation Retirement Plan for Non-Employee Directors, as amended and terminated January 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1997 (File No. 1-12609), Exhibit 10.13)
*10.31	PG&E Corporation Long-Term Incentive Program, as amended May 16, 2001, including the PG&E Corporation Stock Option Plan, Performance Unit Plan, and Non-Employee Director Stock Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
*10.32	PG&E Corporation Executive Stock Ownership Program Guidelines dated as of February 19, 2003 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609) Exhibit 10.2)
*10.33	PG&E Corporation Officer Severance Policy, amended as of December 19, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.43)

Exhibit Number	Exhibit Description
*10.34	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
*10.35	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.2)
*10.36	PG&E Corporation 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)
*10.37	Form of Restricted Stock Award Agreement for 2004 grants made under the PG&E Corporation Long-Term Incentive Program
*10.38	Form of Performance Share Award Agreement granted under the PG&E Corporation Long-Term Incentive Program
*10.39	PG&E National Energy Group, Inc. Management Retention/ Performance Award Program (incorporated by reference to PG&E Corporation's Form 10-K/ A Amendment No. 2 for the year ended December 31, 2002 (File No. 1-12609) Exhibit 10.47)
*10.39.1	Letter regarding retention award to Thomas B. King dated September 9, 2002 (incorporated by reference to PG&E Corporation's Form 10-K/ A Amendment No. 2 for the year ended December 31, 2002 (File No. 1-12609) Exhibit 10.47.1)
*10.39.2	Letter regarding retention award to P. Chrisman Iribe dated September 9, 2002 (incorporated by reference to PG&E Corporation's Form 10-K/ A Amendment No. 2 for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.47.2)
*10.39.3	Letter regarding retention award to Lyn E. Maddox dated September 9, 2002 (incorporated by reference to PG&E Corporation's Form 10-K/ A Amendment No. 2 for the year ended December 31, 2002 (File No. 1-12609) Exhibit 10.47.3)
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 2003 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," "Independent Auditors' Report," "Responsibility for Consolidated Financial Statements," financial statements of PG&E Corporation entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Common Shareholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," "Consolidated Statements of Shareholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)"
21	Subsidiaries of the Registrant
23	Independent Auditors' Consent (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

Exhibit Number	Exhibit Description
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.

(b) The following Current Reports on Form 8-K(1) were filed, or furnished as indicated, during the quarter ended December 31, 2003, and through the date hereof:

1.	October 3, 2003	Item 9.	Regulation FD Disclosure (furnished to the SEC) Exhibit 1 — Pacific Gas and Electric Company Income Statement for the month ended August 31, 2003 and Balance Sheet dated August 31, 2003
2.	October 15, 2003	Item 5.	Other Events District Court ruling regarding California Business and Professions Code Section 17200 lawsuits
		Item 9.	Regulation FD Disclosure (furnished to the SEC) Exhibit 1 — Revised Financial Projections Relating to the Settlement Plan
3.	October 24, 2003	Item 5.	Other Events A. Credit Rating Change B. Department of Water Resources' (DWR) 2001-2002 Revenue Requirement True-Up Proceeding
4.	November 12, 2003	Item 12.	Results of Operations and Financial Condition (furnished to the SEC) Release of Third Quarter Earnings Results
5.	November 20, 2003	Item 5.	Other Events A. Proposed Decisions Regarding Proposed Settlement Agreement B. Conclusion of Confirmation Trial Testimony in Utility's Chapter 11 Proceeding C. Ninth Circuit Preemption Decision
6.	December 2, 2003	Item 9.	Regulation FD Disclosure (furnished to the SEC) Exhibit 1 — Pacific Gas and Electric Company Income Statement for the month ended October 31, 2003 and Balance Sheet dated October 31, 2003
7.	December 9, 2003	Item 5.	Other Events A. Additional Proposed Decisions Regarding Proposed Settlement Agreement B. Credit Rating Agency Announcement

8.	December 12, 2003	Item 5.	Other Events Proposed Decision Issued in the California Department of Water Resources” (DWR) 2001-2002 Revenue Requirement True-Up Proceeding and the DWR 2004 Revenue Requirement Proceeding
9.	December 15, 2003	Item 5.	Other Events Bankruptcy Court Decision Approving Proposed Chapter 11 Settlement Agreement and Plan of Reorganization
10.	December 16, 2003	Item 5.	Other Events Comments Regarding Proposed Settlement Agreement Filed by the Utility and TURN
11.	December 22, 2003	Item 5.	Other Events A. California Public Utilities Commission Approves Proposed Settlement Agreement as Recommended to be Modified by Pacific Gas and Electric Company and The Utility Reform Network B. CPUC Approves Gas Accord II
		Item 7.	Financial Statements, Pro Forma Financial Information, and Exhibits Exhibit 99 — 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
12.	December 23, 2003	Item 5.	Other Events Bankruptcy Court Confirms Utility’s Plan of Reorganization
13.	December 31, 2003	Item 9.	Regulation FD Disclosure (furnished to the SEC) Exhibit 1 — Pacific Gas and Electric Company Income Statement for the month ended November 30, 2003 and Balance Sheet dated November 30, 2003
14.	January 22, 2004	Item 5.	Other Events Applications Filed for Rehearing of CPUC Decision Approving Chapter 11 Settlement Agreement
		Item 7.	Financial Statements, Pro Forma Financial Information, and Exhibits Exhibit 99 — Notice to Directors and Executive Officers, dated January 22, 2004
		Item 11.	Temporary Suspension of Trading Under Registrant’s Employee Benefits Plan
15.	February 3, 2004	Item 5.	Other Events Implementation of Chapter 11 Settlement Rate Reduction
16.	February 19, 2004	Item 5.	Other Events
		Item 7.	Financial Statements, Pro Forma Financial Information, and Exhibits Exhibit 99 — Amendment to Rights Agreement dated February 18, 2004, between PG&E Corporation and Mellon Investor Services LLC
		Item 12.	Results of Operations and Financial Condition (furnished to the SEC) Release of Third Quarter Earnings Results

(1) Unless otherwise noted, all reports were filed under Commission File Number 1-2348 (Pacific Gas and Electric Company) and Commission File Number 1-12609 (PG&E Corporation).

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, 2003 to be signed on their behalf by the undersigned, thereunto duly authorized, in the City and County of San Francisco, on the 19th day of February, 2004.

PG&E CORPORATION (Registrant) By GARY P. ENCINAS (Gary P. Encinas, Attorney-in-Fact)	PACIFIC GAS AND ELECTRIC COMPANY (Registrant) By GARY P. ENCINAS (Gary P. Encinas, 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 *ROBERT D. GLYNN, JR. *GORDON R. SMITH	Chairman of the Board, Chief Executive Officer, and President (PG&E Corporation) President and Chief Executive Officer (Pacific Gas and Electric Company)	February 19, 2004 February 19, 2004
B. Principal Financial Officers *PETER A. DARBEE *KENT M. HARVEY	Senior Vice President and Chief Financial Officer (PG&E Corporation) Senior Vice President, Chief Financial Officer, and Treasurer (Pacific Gas and Electric Company)	February 19, 2004 February 19, 2004
C. Principal Accounting Officers *CHRISTOPHER P. JOHNS *DINYAR B. MISTRY	Senior Vice President and Controller (PG&E Corporation) Vice President-Controller (Pacific Gas and Electric Company)	February 19, 2004 February 19, 2004
D. Directors *LESLIE S. BILLER *DAVID A. COULTER *C. LEE COX *WILLIAM S. DAVILA *ROBERT D. GLYNN, JR. *DAVID M. LAWRENCE, M.D. *MARY S. METZ *CARL E. REICHARDT *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 19, 2004

*By GARY P. ENCINAS

(Gary P. Encinas, Attorney-in-Fact)

INDEPENDENT AUDITORS' REPORT

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

We have audited the consolidated financial statements of PG&E Corporation and subsidiaries and of Pacific Gas and Electric Company (a Debtor-in-Possession) and subsidiaries (collectively, the "Companies") as of December 31, 2003 and 2002, and for each of the three years in the period ended December 31, 2003 and have issued our report thereon dated February 18, 2004 (which report expresses an unqualified opinion and includes explanatory paragraphs relating to accounting changes, a revision to the 2002 and 2001 financial statements of PG&E Corporation and going concern uncertainties). Such consolidated financial statements of each of the Companies are included in the combined 2003 Annual Report to Shareholders (of PG&E Corporation and Pacific Gas and Electric Company) and are incorporated herein by reference. Our audits also included the respective consolidated financial statement schedules of PG&E Corporation and Pacific Gas and Electric Company, listed in Item 15(a)2. These consolidated financial statement schedules are the responsibility of the respective managements of PG&E Corporation and Pacific Gas and Electric Company. 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 respective basic consolidated financial statements of PG&E Corporation and Pacific Gas and Electric Company taken as a whole, present fairly in all material respects the information set forth therein.

DELOITTE & TOUCHE LLP

San Francisco, California
February 18, 2004

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT

CONDENSED BALANCE SHEETS

	Balance at December 31,	
	2003	2002
	(In millions)	
ASSETS		
Cash and cash equivalents	\$ 673	\$ 182
Restricted cash	—	377
Advances to affiliates	398	479
Note receivable from subsidiary	—	208
Other current assets	9	1
Total current assets	1,080	1,247
Equipment	20	20
Accumulated depreciation	(15)	(12)
Net equipment	5	8
Restricted Cash	361	—
Investments in subsidiaries	4,810	2,870
Other investments	24	33
Deferred income taxes	478	702
Other	32	34
Total Assets	\$ 6,790	\$ 4,894
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable — related parties	\$ 2	\$ 31
Accounts payable — other	28	38
Income taxes payable	258	133
Other	158	57
Total current liabilities	446	259
Noncurrent Liabilities:		
Long-term debt	883	976
Net investment in NEG T	1,216	—
Other	30	46
Total noncurrent liabilities	2,129	1,022
Preferred Stock	—	—
Common Shareholders' Equity		
Common stock	6,468	6,274
Common stock held by subsidiary	(690)	(690)
Unearned compensation	(20)	—
Accumulated deficit	(1,458)	(1,878)
Accumulated other comprehensive income	(85)	(93)
Total common shareholders' equity	4,215	3,613
Total Liabilities and Shareholders' Equity	\$ 6,790	\$ 4,894

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT — (Continued)

CONDENSED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
	(In millions except per share amounts)		
Administrative service revenue	\$ 101	\$ 96	\$ 95
Equity in earnings of subsidiaries	917	1,842	1,087
Operating expenses	(133)	(141)	(108)
Interest income	20	30	35
Interest expense	(200)	(253)	(132)
Other income	2	81	4
Income before income taxes	707	1,655	981
Less: Income tax benefit	(84)	(68)	(40)
Income from continuing operations	791	1,723	1,021
Discontinued operations	(365)	(2,536)	69
Cumulative effect of changes in accounting principles	(6)	(61)	9
Net income (loss) before intercompany elimination	\$ 420	\$ (874)	\$ 1,099
Weighted Average Common Shares Outstanding	385	371	363
Earnings (Loss) Per Common Share, Basic	\$ 1.09	\$ (2.36)	\$ 3.03
Earnings (Loss) Per Common Share, Diluted	\$ 1.06	\$ (2.26)	\$ 3.02

CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2003, 2002 and 2001

	2003	2002	2001
	(In millions)		
Cash Flows from Operating Activities:			
Net income (loss)	\$ 420	\$ (874)	\$ 1,099
Loss (income) from discontinued operations	365	2,536	(69)
Cumulative effect of changes in accounting principles	6	61	(9)
Net income from continuing operations	791	1,723	1,021
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Equity in earnings of subsidiaries	(917)	(1,842)	(1,087)
Deferred taxes	265	(660)	(51)
Other-net	391	458	237
Net cash provided (used) by operating activities	530	(321)	120
Cash Flows From Investing Activities:			
Capital expenditures	—	(1)	(4)
Net cash used by investing activities	—	(1)	(4)
Cash Flows From Financing Activities:			
Common stock issued	166	217	15
Common stock repurchased	—	—	(1)
Long-term debt issued	581	847	907
Long-term debt redeemed	(787)	(908)	—
Short-term debt issued redeemed	—	—	(931)
Dividends paid	—	—	(109)
Other-net	1	—	—

Net cash provided (used) by financing activities	(39)	156	(119)
Net Change in Cash & Cash Equivalents	491	(166)	(3)
Cash & Cash Equivalents at January 1	182	348	351
Cash & Cash Equivalents at December 31	\$ 673	\$ 182	\$ 348

PG&E CORPORATION

SCHEDULE II — CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2003, 2002 and 2001

Description	Balance at Beginning of Period	Additions		Deductions	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts		
(in millions)					
Valuation and qualifying accounts deducted from assets:					
2003:					
Allowance for uncollectible accounts ⁽¹⁾⁽²⁾	\$ 59	\$ 42	\$—	\$ 33 ⁽³⁾	\$ 68
2002:					
Allowance for uncollectible accounts ⁽¹⁾⁽²⁾	\$ 48	\$ 34	\$ (2)	\$ 23 ⁽³⁾	\$ 59
2001:					
Allowance for uncollectible accounts ⁽¹⁾⁽²⁾	\$ 52	\$ 24	\$—	\$ 28 ⁽³⁾	\$ 48
Provision for loss on generation-related regulatory assets and undercollected purchased power costs ⁽⁴⁾	\$6,939	\$ —	\$—	\$6,939	\$ —

(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.

(4) Provision was deduction from “Regulatory Assets.”

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR IN POSSESSION

SCHEDULE II — CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS
For the Years Ended December 31, 2003, 2002 and 2001

Description	Balance at Beginning of Period	Additions		Deductions	Balance at End of Period
		Charged to Costs and Expenses	Charged to Other Accounts		
(in millions)					
Valuation and qualifying accounts deducted from assets:					
2003:					
Allowance for uncollectible accounts ⁽¹⁾	\$ 59	\$ 42	\$—	\$ 33 ⁽²⁾	\$ 68
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Allowance for uncollectible accounts ⁽¹⁾	\$ 48	\$ 34	\$ (2)	\$ 23 ⁽²⁾	\$ 59
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Allowance for uncollectible accounts ⁽¹⁾	\$ 52	\$ 24	\$—	\$ 28 ⁽²⁾	\$ 48
Provision for loss on generation-related regulatory assets and undercollected purchased power costs ⁽³⁾	\$6,939	\$ —	\$—	\$6,939	\$ —

(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.

(3) Provision was deduction from “Regulatory Assets.”

EXHIBIT INDEX

Exhibit Number	Exhibit Description
3.1	Restated Articles of Incorporation of PG&E Corporation effective as of May 5, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (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 February 18, 2004
3.4	Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of May 6, 1998 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-2348), Exhibit 3.1)
3.5	Bylaws of Pacific Gas and Electric Company amended as of February 18, 2004
4.1	First and Refunding Mortgage of Pacific Gas and Electric Company dated December 1, 1920, and supplements thereto dated April 23, 1925, October 1, 1931, March 1, 1941, September 1, 1947, May 15, 1950, May 1, 1954, May 21, 1958, November 1, 1964, July 1, 1965, July 1, 1969, January 1, 1975, June 1, 1979, August 1, 1983, and December 1, 1988 (incorporated by reference to Registration No. 2-1324, Exhibits B-1, B-2, and B-3; Registration No. 2-4676, Exhibit B-22; Registration No. 2-7203, Exhibit B-23; Registration No. 2-8475, Exhibit B-24; Registration No. 2-10874, Exhibit 4B; Registration No. 2-14144, Exhibit 4B; Registration No. 2-22910, Exhibit 2B; Registration No. 2-23759, Exhibit 2B; Registration No. 2-35106, Exhibit 2B; Registration No. 2-54302, Exhibit 2C; Registration No. 2-64313, Exhibit 2C; Registration No. 2-86849, Exhibit 4.3; and Pacific Gas and Electric Company's Form 8-K dated January 18, 1989 (File No. 1-2348), Exhibit 4.2)
4.2	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).
4.3	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 Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.1)
4.4	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).
4.5	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 Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12609), Exhibit 4.2)
4.6	Form of Rights Agreement dated as of December 22, 2000, between PG&E Corporation and Mellon Investor Services LLC, including the Form of Rights Certificate as Exhibit A, the Summary of Rights to Purchase Preferred Stock as Exhibit B, and the Form of Certificate of Determination of Preferences for the Preferred Stock as Exhibit C (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 4.2)
4.7	Amendment to Rights Agreement dated February 18, 2004, between PG&E Corporation and Mellon Investor Services LLC (incorporated by reference to PG&E Corporation's Form 8-K filed February 19, 2004 (file No. 1-12609), Exhibit 99)
4.8	Indenture dated as of July 2, 2003, by and between PG&E Corporation and Bank One, N.A. (incorporated by reference to PG&E Corporation's Form 8-K filed July 2, 2003 (file No. 1-12609), Exhibit 4.1)
4.9	Utility Stock Base Pledge Agreement dated as of July 2, 2003, by and among PG&E Corporation, Bank One, N.A. and Deutsche Bank Trust Company Americas (incorporated by reference to PG&E Corporation's Form 8-K filed July 2, 2003 (file No. 1-12609), Exhibit 4.2)

Exhibit Number	Exhibit Description
4.10	Utility Stock Protective Pledge Agreement dated as of July 2, 2003, by and among PG&E Corporation, Bank One, N.A. and Deutsche Bank Trust Company Americas (incorporated by reference to PG&E Corporation's Form 8-K filed July 2, 2003 (file No. 1-12609), Exhibit 4.3)
4.11	Form of 6 7/8 percent Senior Secured Note due 2008 (incorporated by reference to PG&E Corporation's Form 8-K filed July 2, 2003 (file No. 1-12609), Exhibit 4.4)
10.1	The Gas Accord Settlement Agreement, together with accompanying tables, adopted by the California Public Utilities Commission on August 1, 1997, in Decision 97-08-055 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 1997 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2), as amended by Operational Flow Order (OFO) Settlement Agreement, approved by the California Public Utilities Commission on February 17, 2000, in Decision 00-02-050, as amended by Comprehensive Gas OII Settlement Agreement, approved by the California Public Utilities Commission on May 18, 2000, in Decision 00-05-049 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10); and the Gas Accord II Settlement Agreement, approved by the California Public Utilities Commission on August 22, 2002, in Decision 01-09-016 (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 10.1)
10.2	Commitment Letter dated March 5, 2003, between PG&E Corporation and Lehman Brothers, Inc. (incorporated by reference to PG&E Corporation's Form 8-K filed March 6, 2003) (File No. 1-12609), Exhibit 99.2)
10.3	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)
10.4	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
10.5	Operating Agreement between Pacific Gas and Electric Company and Pacific Gas Transmission Company dated July 9, 1996
10.6	PG&E Trans-User Agreement between Pacific Gas and Electric Company and PG&E Gas Transmission, Northwest Corporation dated November 15, 1999
10.7	Electronic Commerce System User Agreement between Pacific Gas and Electric Company and PG&E Gas Transmission, Northwest Corporation, effective as of September 28, 2001
10.8	Operating Agreement effective as of April 1, 2003, between the State of California Department of Water Resources and Pacific Gas and Electric Company (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348); Exhibit 10.1)
*10.9	PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2001 (File No. 1-12609), Exhibit 10.4)
*10.10	Agreement and Release between PG&E Corporation and Thomas G. Boren, dated December 18, 2002 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.23)
*10.11	Description of Compensation Arrangement between PG&E Corporation and Peter Darbee (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1999 (File No. 1-12609), Exhibit 10.3)
*10.12	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)
*10.13	Letter regarding Compensation Arrangement between PG&E Corporation and Lyn E. Maddox dated April 25, 1997 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.7)

Exhibit Number	Exhibit Description
*10.14	Letter Regarding Relocation Arrangement Between PG&E Corporation and Thomas B. King dated March 16, 2000 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2000 (File No. 1-12609), Exhibit 10)
*10.15	Description of Relocation Arrangement Between PG&E Corporation and Lyn E. Maddox (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.9)
*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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609); Exhibit 10.3)
*10.17	Letter regarding Compensation Arrangement between PG&E Corporation and Peter A. Darbee effective June 18, 2003 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609); Exhibit 10.4)
*10.18	PG&E Corporation Senior Executive Officer Retention Program approved December 20, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10)]
*10.19.1	Letter regarding retention award to Robert D. Glynn, Jr. dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.1)
*10.19.2	Letter regarding retention award to Gordon R. Smith dated January 22, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.2)
*10.19.3	Letter regarding retention award to Peter A. Darbee dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.3)
*10.19.4	Letter regarding retention award to Bruce R. Worthington dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.4)
*10.19.5	Letter regarding retention award to G. Brent Stanley dated January 22, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.5)
*10.19.6	Letter regarding retention award to Daniel D. Richard, Jr. dated January 22, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.6)
*10.19.7	Letter regarding retention award to James K. Randolph dated February 27, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.7)
*10.19.8	Letter regarding retention award to Gregory M. Rueger dated February 27, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.8)
*10.19.9	Letter regarding retention award to Kent M. Harvey dated February 27, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.9)
*10.19.10	Letter regarding retention award to Roger J. Peters dated February 27, 2001 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2000 (File No. 1-12609 and File No. 1-2348), Exhibit 10.10.10)
*10.19.11	Letter regarding retention award to Lyn E. Maddox dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.12)
*10.19.12	Letter regarding retention award to P. Chrisman Iribe dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.13)

Exhibit Number	Exhibit Description
*10.19.13	Letter regarding retention award to Thomas B. King dated February 27, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 10.10.14)
*10.20	Pacific Gas and Electric Company Management Retention Program (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609 and File No. 1-2348), Exhibit 10.1)
*10.21	PG&E Corporation Management Retention Program (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2001 (File No. 1-12609), Exhibit 10.2)
*10.22	PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2)
*10.23	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2003 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.35)
*10.24	Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2004
*10.25	Supplemental Executive Retirement Plan of the Pacific Gas and Electric Company amended as of September 19, 2001 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2001 (File No. 1-2248), Exhibit 10.16)
*10.26.1	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)
*10.26.2	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)
*10.26.3	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)
*10.26.4	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)
*10.26.5	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)
*10.26.6	Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and Thomas G. Boren 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 10.37.6)
*10.27.1	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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609); Exhibit 10.2.1)
*10.27.2	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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348); Exhibit 10.2.2)

Exhibit Number	Exhibit Description
*10.27.3	Agreement and Release regarding annuitization of SERP benefits by and between PG&E Corporation and James K. Randolph dated April 18, 2003 (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348); Exhibit 10.2.3)
*10.27.4	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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609 and File No. 1-2348); Exhibit 10.2.4)
*10.27.5	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 Form 10-Q for the quarter ended June 30, 2003 (File No. 1-12609); Exhibit 10.2.5)
*10.28	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)
*10.29	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)
*10.30	PG&E Corporation Retirement Plan for Non-Employee Directors, as amended and terminated January 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 1997 (File No. 1-12609), Exhibit 10.13)
*10.31	PG&E Corporation Long-Term Incentive Program, as amended May 16, 2001, including the PG&E Corporation Stock Option Plan, Performance Unit Plan, and Non-Employee Director Stock Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10)
*10.32	PG&E Corporation Executive Stock Ownership Program Guidelines dated as of February 19, 2003 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609); Exhibit 10.2)
*10.33	PG&E Corporation Officer Severance Policy, amended as of December 19, 2001 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2002 (File No. 1-12609), Exhibit 10.43)
*10.34	PG&E Corporation Director Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.1)
*10.35	PG&E Corporation Officer Grantor Trust Agreement dated April 1, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 1998 (File No. 1-12609), Exhibit 10.2)
*10.36	PG&E Corporation 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)
*10.37	Form of Restricted Stock Award Agreement for 2004 grants made under the PG&E Corporation Long-Term Incentive Program
*10.38	Form of Performance Share Award Agreement granted under the PG&E Corporation Long-Term Incentive Program
*10.39	PG&E National Energy Group, Inc. Management Retention/ Performance Award Program (incorporated by reference to PG&E Corporation's Form 10-K/A Amendment No. 2 for the year ended December 31, 2002 (File No. 1-12609); Exhibit 10.47)
*10.39.1	Letter regarding retention award to Thomas B. King dated September 9, 2002 (incorporated by reference to PG&E Corporation's Form 10-K/ A Amendment No. 2 for the year ended December 31, 2002 (File No. 1-12609); Exhibit 10.47.1)

Exhibit Number	Exhibit Description
*10.39.2	Letter regarding retention award to P. Chrisman Iribe dated September 9, 2002 (incorporated by reference to PG&E Corporation's Form 10-K/ A Amendment No. 2 for the year ended December 31, 2002 (File No. 1-12609); Exhibit 10.47.2)
*10.39.3	Letter regarding retention award Lyn E. Maddox dated September 9, 2002 (incorporated by reference to PG&E Corporation's Form 10-K/ A Amendment No. 2 for the year ended December 31, 2002 (File No. 1-12609); Exhibit 10.47.3)
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 2003 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," "Independent Auditors' Report," "Responsibility for Consolidated Financial Statements," financial statements of PG&E Corporation entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," and "Consolidated Statements of Common Shareholders' Equity," financial statements of Pacific Gas and Electric Company entitled "Consolidated Statements of Operations," "Consolidated Balance Sheets," "Consolidated Statements of Cash Flows," "Consolidated Statements of Shareholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)"
21	Subsidiaries of the Registrant
23	Independent Auditors' Consent (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.

EXHIBIT 3.3

BYLAWS OF PG&E CORPORATION AMENDED AS OF FEBRUARY 18, 2004

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 3.5

**BYLAWS
OF
PACIFIC GAS AND ELECTRIC COMPANY
AMENDED AS OF FEBRUARY 18, 2004**

**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 10.4

FIRM TRANSPORTATION SERVICE AGREEMENT

THIS AGREEMENT is made and entered into this 26th day of October, 1993, by and between

PACIFIC GAS TRANSMISSION COMPANY, a California corporation (hereinafter referred to as "PGT"),

and

PACIFIC GAS AND ELECTRIC COMPANY, a corporation existing under the laws of the State of California, (hereinafter referred to as "Shipper").

WHEREAS, PGT owns and operates a natural gas pipeline transmission system which extends from a point of interconnection with the pipeline facilities of Alberta Natural Gas Company Ltd. (ANG) at the International Boundary near Kingsgate, British Columbia, through the states of Idaho, Washington and Oregon to a point of interconnection with Pacific Gas and Electric Company at the Oregon-California border near Malin, Oregon; and

WHEREAS, Shipper desires PGT, on a firm basis, to transport certain quantities of natural gas from Kingsgate, British Columbia to Malin, Oregon for ultimate delivery to Shipper, a local distribution company; and

WHEREAS, pursuant to FERC Order No. 636, et seq., PGT will unbundle its firm transportation and sales services, and PGT and Shipper will execute a new service agreement for unbundled firm transportation service; and

WHEREAS, this Agreement will supersede and prior agreements between PGT and Shipper for firm gas sales or firm transportation, and will incorporate the transportation rights thereunder into this Agreement; and

WHEREAS, PGT is willing to transport certain quantities of natural gas for Shipper, on a firm basis,

NOW, THEREFORE, the parties agree as follows:

I GOVERNMENTAL AUTHORITY

1.1 This Firm Transportation Agreement ("Agreement") is made pursuant to the regulations of the Federal Energy Regulatory Commission (FERC) contained in 18 CFR Part 284, as amended from time to time.

I
GOVERNMENTAL AUTHORITY
(CONTINUED)

1.2 This Agreement is subject to all valid legislation with respect to the subject matters hereof, either state or federal, and to all valid present and future decisions, orders, rules, regulations and ordinances of all duly constituted governmental authorities having jurisdiction.

1.3 Shipper shall reimburse PGT for any and all filing fees incurred by PGT in seeking governmental authorization for the initiation, extension, or termination of service under this Agreement and Rate Schedule FTS-1. Shipper shall reimburse PGT for such fees at PGT's designated office within ten (10) days of receipt of notice from PGT that such fees are due and payable. Additionally, Shipper shall reimburse PGT for any and all penalty fees or fines assessed PGT caused by the negligence of Shipper in not obtaining all proper Canadian and domestic import/export licenses, surety bonds or any other documents and approvals related to the Canadian exportation and subsequent domestic importation of natural gas transported by PGT hereunder.

II
QUANTITY OF GAS AND PRIORITY OF SERVICE

2.1 Subject to the terms and provisions of this Agreement and PGT's Transportation General Terms and Conditions contained in PGT's FERC Gas Tariff First Revised Volume No. 1-A (Transportation General Terms and Conditions) applicable to Rate Schedule FTS-1, daily receipts of gas by PGT from Shipper at the point(s) of receipt shall be equal to daily deliveries of gas by PGT to Shipper at the point(s) of delivery; provided, however, Shipper shall deliver to PGT an additional quantity of natural gas at the point(s) of receipt as compressor station fuel, line loss and unaccounted for gas as specified in the Statement of Effective Rates and Charges of PGT's FERC Gas Tariff First Revised Volume No. 1-A which by this reference is made a part hereof. Any limitation of the quantities to be received from each point of receipt and/or delivered to each point of delivery shall be as specified on the Exhibit A attached hereto.

2.2 The maximum quantities of gas to be delivered by PGT for Shipper's account at the point(s) of delivery are set forth in Exhibit A.

2.3 In providing service to its existing or new customers, PGT will use the priorities of service specified in Paragraph 18 of PGT's Transportation General Terms and Conditions on file with the FERC.

2.4 Prior to initiation of service, Shipper shall provide PGT with any information required by the FERC, as well as the information identified in Paragraphs 21, 28, and 29 of PGT's Transportation General Terms and Conditions applicable to Rate Schedule FTS-1.

III
TERM OF AGREEMENT

3.1 This Agreement shall become effective November 1, 1993, and shall continue in full force and effect until October 31, 2005. Thereafter, this Agreement shall continue in effect from year to year unless Shipper gives PGT twelve (12) months prior written notice of termination of this Agreement. The Agreement shall terminate twelve (12) months after such notice.

IV
POINTS OF RECEIPT AND DELIVERY

4.1 The primary point of receipt of gas deliveries to PGT is as designated in Exhibit A, attached hereto.

4.2 The primary point of delivery of gas to Shipper is as designated in Exhibit A, attached hereto.

4.3 Shipper shall deliver or cause to be delivered to PGT the gas to be transported hereunder at pressures sufficient to deliver such gas into PGT's system at the point(s) of receipt. PGT shall deliver the gas to be transported hereunder to or for the account of Shipper at the pressures existing in PGT's system at the point(s) of delivery.

4.4 Pursuant to Paragraph 29 of PGT's Transportation General Terms and Conditions, Shipper may designate other receipt and/or delivery points as secondary receipt or delivery points.

V
OPERATING PROCEDURE

5.1 Shipper shall conform to the operating procedures set forth in PGT's Transportation General Terms and Conditions.

5.2 Nothing in Section 5.1 shall compel PGT to transport gas pursuant to Shipper's request on any given day. PGT shall have the right to interrupt or curtail the transport of gas for the account of Shipper pursuant to PGT's Transportation General Terms and Conditions applicable to Rate Schedule FTS-1.

VI
RATE(S), RATE SCHEDULES, AND
GENERAL TERMS AND CONDITIONS OF SERVICE

6.1 Shipper shall pay PGT each month for services rendered pursuant to this Agreement in accordance with PGT's Rate Schedule FTS-1, or superseding rate schedule(s), on file with and subject to the jurisdiction of FERC.

VI
RATE(S), RATE SCHEDULES, AND
GENERAL TERMS AND CONDITIONS OF SERVICE
(CONTINUED)

6.2 Shipper shall compensate PGT each month for compressor station fuel, line loss and other unaccounted for gas associated with this transportation service provided herein in accordance with PGT's Rate Schedule FTS-1, or superseding rate schedule(s), on file with and subject to the jurisdiction of the FERC.

6.3 This Agreement in all respects shall be and remains subject to the applicable provisions of Rate Schedule FTS-1, or superseding rate schedule(s) and of the applicable Transportation General Terms and Conditions of PGT's FERC Gas Tariff First Revised Volume No. 1-A on file with the FERC, all of which are by this reference made a part hereof.

6.4 PGT shall have the unilateral right from time to time to propose and file with FERC such changes in the rates and charges applicable to transportation services pursuant to this Agreement, the rate schedule(s) under which this service is hereunder provided, or any provisions of PGT's Transportation General Terms and Conditions applicable to such services. Shipper shall have the right to protest any such changes proposed by PGT and to exercise any other rights that Shipper may have with respect thereto.

VII
MISCELLANEOUS

7.1 This Agreement shall be interpreted according to the laws of the State of California.

7.2 Shipper agrees to indemnify and hold PGT harmless for refusal to transport gas hereunder in the event any upstream or downstream transporter fails to receive or deliver gas as contemplated by this Agreement.

VII
MISCELLANEOUS
(CONTINUED)

7.3 Unless herein provided to the contrary, any notice called for in this Agreement shall be in writing and shall be considered as having been given if delivered by registered mail or telex with all postage or charges prepaid, to either PGT or Shipper at the place designated below. Routine communications, including monthly statements and payment, shall be considered as duly delivered when received by ordinary mail. Unless changed, the addresses of the parties are as follows:

"PGT" PACIFIC GAS TRANSMISSION COMPANY
160 Spear Street

Room 1900
San Francisco, California 94105-1570

ATTENTION: President & CEO

"SHIPPER" PACIFIC GAS & ELECTRIC COMPANY
77 Beale Street, Room 1611
Mail Code B16A, P. O. Box 770000
San Francisco, CA 94177
ATTENTION: Mgr. Gas Services Dept.

7.4 A waiver by either party of any one or more defaults by the other hereunder shall not operate as a waiver of any future default or defaults, whether of a like or of a different character.

7.5 This Agreement may only be amended by an instrument in writing executed by both parties hereto.

7.6 Nothing in this Agreement shall be deemed to create any rights or obligations between the parties hereto after the expiration of the term set forth herein, except that termination of this Agreement shall not relieve either party of the obligation to correct any quantity imbalances or Shipper of the obligation to pay any amounts due hereunder to PGT.

7.7 Exhibits A and C attached hereto are incorporated herein by reference and made a part hereof for all purposes.

IN WITNESS WHEREOF the parties have caused this Agreement to be executed as of the day and year first above written.

PACIFIC GAS TRANSMISSION COMPANY

By: /s/ Paula G. Rosput

Name: Paula G. Rosput
Title: Senior Vice President
Date: October 26, 1993

PACIFIC GAS & ELECTRIC COMPANY

By: /s/ William R. Mazotti

Name: William R. Mazotti
Title: Vice President - Gas Services & Operations
Date: October 26, 1993

EXHIBIT A

**TO THE
FIRM TRANSPORTATION SERVICE AGREEMENT
DATED _____ BETWEEN
PACIFIC GAS TRANSMISSION COMPANY
AND
PACIFIC GAS & ELECTRIC COMPANY**

RECEIPT POINT (1) -----	DELIVERY POINT(1) -----	MAXIMUM DAILY QUANTITY (MDQ) (DELIVERED) MMBTU/D -----	
		SUMMER(2) -----	WINTER(3) -----
KINGSGATE	MALIN	1, 023, 120(4)	1, 081, 990

(1) Pursuant to Paragraph 29 of PGT's Transportation General Terms and Conditions, Shipper may designate other receipt and delivery points as "secondary receipt" and "secondary delivery" points. For example, Shipper may designate Stanfield, Oregon and/or Spokane, Washington as secondary receipt points.

(2) Summer- - months of May through October.

(3) Winter - - months of November through April,

(4) In accordance with FERC's October 1, 1993 order at Docket n. RS92-46 Shipper's firm Summer MDQ (Delivered) may exceed 1,023,120 MMBtu/d to the extent firm capacity is available on PGT's original system. However, under no circumstances may Shipper's firm Summer MDQ (Delivered) exceed 1,081,990 MMBtu/d.

EXHIBIT C

**TO THE
FIRM TRANSPORTATION SERVICE AGREEMENT
DATED _____ BETWEEN
PACIFIC GAS TRANSMISSION COMPANY
AND
PACIFIC GAS & ELECTRIC COMPANY**

Type of Replacement Service:

Replacement Shipper:

Receipt Point:

Delivery Point:

Maximum Daily Quantity:

Commencement of Credit:

Termination of Credit:

Level of Credit: _____percent of the maximum rate defined as

Applicable for service under Rate Schedule FTS-1

Other Terms and Conditions:

1) _____

2) _____

3) _____

**RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE**

1. AVAILABILITY

This rate schedule is available to any party (hereinafter called "Shipper") qualifying for service pursuant to the Commission's Regulations contained in 18 CFR Part 284, and who has executed a Firm Transportation Service Agreement with GTN in the form contained in this FERC Gas Tariff, Third Revised Volume No. 1-A.

2. APPLICABILITY AND CHARACTER OF SERVICE

This rate schedule shall apply to firm gas transportation services performed by GTN for Shipper pursuant to the executed Firm Transportation Service Agreement between GTN and Shipper. GTN shall receive from Shipper such daily quantities of gas up to the Shipper's Maximum Daily Quantity as specified in the executed Firm Transportation Service Agreement between GTN and Shipper plus the required quantity of gas for fuel and line loss associated with service under this Rate Schedule FTS-1 and redeliver an amount equal to the quantity received less the required quantity of gas for fuel and line loss. This transportation service shall be firm and not subject to curtailment or interruption except as provided in the Transportation General Terms and Conditions.

Firm transportation service shall be subject to all provisions of the executed Firm Transportation Service Agreement between GTN and Shipper and the applicable Transportation General Terms and Conditions.

3. RATES

Shipper shall pay GTN each month the sum of the Reservation Charge, the Delivery Charge, plus any applicable Extension Charge, Overrun Charge and applicable surcharges for the quantities of natural gas delivered. The rate(s) set forth in GTN's current Effective Rates and Charges for Transportation of Natural Gas in this FERC Gas Tariff, Third Revised Volume No. 1-A are applied to transportation service rendered under this rate schedule.

(Continued)

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RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

3. RATES (Continued)

3.1 Reservation Charge

The Reservation Charge shall be the sum of the Mileage and the Non-Mileage Component:

(a) Mileage Component

The Mileage Component shall be the product of the currently effective Mileage Rate as set forth on Effective Tariff Sheet No. 4, the distance, in pipeline miles, from the Primary Point(s) of receipt to the Primary Point(s) of Delivery on Mainline Facilities as set forth in Shipper's Contract, and the Shipper's Maximum Daily Quantity at such Point(s).

(b) Non-Mileage Component

The Non-Mileage Component shall be the product of the currently effective Non-Mileage Rate as set forth on Effective Tariff Sheet No. 4 and the Shipper's Maximum Daily Quantity at Primary Point(s) of Delivery on Mainline Facilities.

(c) Mitigation Revenue Recovery Surcharge

If Shipper is a Subject Shipper, the Mitigation Revenue Recovery Surcharge for the Mileage and Non-Mileage Components as set forth on Effective Tariff Sheet No. 4 shall be included in, and become a part of, the maximum Mileage and Non-Mileage Base Reservation Rates used for computing the Mileage and Non-Mileage Components of the Reservation Charge. The Mileage Component shall be designed to recover, on the basis of the mileage billing determinants of the Subject Shippers underlying GTN's currently effective rates, mileage mitigation revenues not recovered from other shippers in accordance with Article IV, Section 1(b) of the Stipulation and Agreement in Docket No. RP94-149-000, et al., and the Non-Mileage Component shall be designed to recover, on the basis of the Non-Mileage billing determinants of the Subject Shippers underlying GTN's currently effective rates, Non-Mileage mitigation revenues not recovered from other shippers in accordance with Article IV, Section 1(b) of the Stipulation and Agreement in Docket No. RP94-149-000, et al.

(Continued)

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RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

3. RATES (Continued)

3.1 Reservation Charge (Continued)

(d) Competitive Equalization Surcharge

The Mileage and Non-Mileage components of the Competitive Equalization Surcharge as set forth on Effective Tariff Sheet No. 4 shall be included in, and become a part of, the maximum Mileage and Non-Mileage Base Reservation Rates used for computing the Mileage and Non-Mileage Components of the Reservation Charge of shippers that have contracted for service utilizing, in whole or in part, CES Capacity under a Firm Transportation Service Agreement having a term of one year or more and shippers that have obtained service rights from such shippers pursuant to Section 28 of the General Terms and Conditions of this FERC Gas Tariff. The Mileage Component shall be equal to the Mileage Component of the Mitigation Revenue Recovery Surcharge and the Non-Mileage Component shall be equal to the Non-Mileage Component of the Mitigation Revenue Recovery Surcharge. Shippers to which the Competitive Equalization Surcharge applies, other than shippers that have obtained service pursuant to Section 28 of the General Terms and Conditions of this FERC Gas Tariff, shall be identified on Effective Tariff Sheet No. 11.

(Continued)

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RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

3. RATES (Continued)

3.1 Reservation Charge (Continued)

(e) Shipper's obligation to pay the Reservation Charge and applicable Reservation Surcharge is independent of Shipper's ability to obtain export authorization from the National Energy Board of Canada, Canadian provincial removal authority, and/or import authorization from the United States Department of Energy, and shall begin with the execution of the Firm Transportation Service Agreement by both parties. The Reservation Charge and Reservation Surcharge due and payable shall be computed beginning in the month in which service is first available (prorated if beginning in the month in which service is available on a date other than the first day of the month). Thereafter, the monthly Reservation Charge and Reservation Surcharge shall be due and payable each month during the Initial (and Subsequent) Term(s) of the Shipper's executed Firm Transportation Service Agreement and is unaffected by the quantity of gas transported by GTN to Shipper's delivery point(s) in any month except as provided for in Paragraphs 3.10 and 3.11 of this rate schedule.

3.2 Delivery Charge

The Delivery Charge shall be the product of the Delivery Rate as set forth on Effective Tariff Sheet No. 4, the quantities of gas delivered in the month (in Dth) (excluding Authorized Overrun) at point(s) of delivery on Mainline Facilities, and the distance, in pipeline miles, from the point (s) of receipt to point(s) of delivery on Mainline Facilities.

(Continued)

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RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

3. RATES (Continued)

3.3 Extension Charge

If Shipper designates a Primary Point of delivery on an Extension Facility, then in addition to all other charges that are applicable, Shipper shall pay the Extension Charge, which shall consist of a reservation and delivery component.

(a) The reservation component of the Extension Charge shall be the product of Shipper's Maximum Daily Quantity at the Primary Point(s) of delivery on the Extension Facility, the applicable Extension reservation rate as set forth on Effective Tariff Sheet No. 4, and the distance, in pipeline miles, from the Receipt Point(s) on the Extension Facility to the Primary Point(s) of delivery.

(b) The delivery component of the Extension Surcharge shall be the product of the quantities delivered at the point(s) of delivery on the Extension Facility, the applicable Extension delivery rate as set forth on Effective Tariff Sheet No. 4, and the distance, in pipeline miles, from the Receipt Point(s) on the Extension Facility to the point(s) of delivery.

3.4 Authorized Overrun Charge

Quantities in excess of Shipper's MDQ shall be transported when capacity is available on the GTN system and when the provision of such Authorized Overruns shall not effect any Shipper's rights on the GTN System. Authorized Overruns are interruptible in nature. The rate charged shall be the same as the rates and charges for interruptible transportation under Rate Schedule ITS-1 as set forth on effective Tariff Sheet No. 4, and such Authorized Overruns shall be subject to the priority of service provisions of Paragraph 19 of the Transportation General Terms and Conditions.

3.5 Applicability of Surcharges

Shipper shall pay all reservation and usage surcharges applicable to the service provided to such Shipper as set forth in GTN's FERC Gas Tariff, Third Revised Volume No. 1-A. such surcharges shall be deemed to be part of Shipper's reservation and Delivery Charges.

(Continued)

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RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

3. RATES (Continued)

3.6 Shipper shall pay the Maximum Reservation Charge, and the Maximum Delivery Charge for service under this Rate Schedule unless GTN offers to discount the Mileage Rate components or the Non-Mileage Rate components of the Reservation Rate or the Delivery Rate or the GRI surcharge under this rate schedule. If GTN elects to discount any such rate, GTN shall, up to forty-eight (48) hours prior to such discount, by written notice, advise Shipper of the effective date of such charges and the quantity of gas so affected; provided, however, such discount shall not be anticompetitive or unduly discriminatory between individual shippers. The rates for service under this rate schedule shall not be discounted below the Minimum Reservation Charge, the Minimum Delivery Rate, and applicable ACA Surcharge.

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RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

3. RATES (Continued)

3.7 Reserved

3.8 Backhauls (as defined in Paragraph 1.30 of the Transportation General Terms and Conditions) shall be subject to the same charges as forward haul (as defined in Paragraph 1.29 of the Transportation General Terms and Conditions) except that no gas shall be retained by GTN for compressor station fuel, line loss and other unaccounted-for gas. Backhauls are subject to the operating conditions of GTN's pipeline and will not be made available to Shipper if GTN determines, in its sole discretion, that such transportation is operationally infeasible or otherwise not available.

3.9 Reserved

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RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

3. RATES (Continued)

3.10 Capacity Release

(a) Releasing Shippers:

Shipper shall have the option to release capacity pursuant to the provisions of GTN's capacity release program as specified in the Transportation General Terms and Conditions. Shipper may release its capacity, up to Shipper's Maximum Daily Quantity under this rate schedule, in accordance with the provisions of Paragraph 28 of GTN's Transportation General Terms and conditions of this FERC Gas Tariff, Third Revised Volume No. 1-A. Shipper shall pay a fee associated with the marketing of capacity by GTN (if applicable) in accordance with Paragraph 28 of the Transportation General Terms and Conditions. This fee shall be negotiated between GTN and the Releasing Shipper.

(b) Replacement Shippers:

Shipper may receive released capacity service under this rate schedule pursuant to Paragraph 28 of the Transportation General Terms and Conditions and is required to execute a service agreement in the form contained for capacity release under Rate Schedule FTS-1 in this Third Revised Volume No. 1-A.

Shipper shall pay GTN each month for transportation service under this rate schedule and as set forth in GTN's current Statement of Effective Rates and Charges in this Third Revised Volume No. 1-A. Charges to be paid shall be the sum of the Reservation Charge, Delivery Charge, and other applicable surcharges or penalties.

The rates paid by Shipper receiving capacity release transportation service shall be adjusted as provided on Exhibit R in the executed Transportation Service Agreement For Capacity Release between GTN and Shipper.

(Continued)

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RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

3.11 Reservation Charge Credit - Malin Primary Delivery Point

If GTN fails to deliver to Malin, Oregon ninety-five percent (95%) or more of the aggregate Confirmed Daily Nominations (as hereinafter defined) of all Shippers with a Malin primary delivery point receiving service under this rate schedule (hereinafter referred to as the "Non-Deficiency Amount") for more than twenty-five (25) days in any given Contract Year, then for each day during that Contract Year in excess of twenty-five (25) days that GTN so fails to deliver the Non-Deficiency Amount (a "Credit Day") Shipper, as its sole remedy, shall be entitled to a Reservation Charge Credit calculated in the manner hereinafter set forth.

For the purpose of this Paragraph 3.10, Confirmed Daily Nomination shall mean for any day, the lesser of (1) Shipper's Maximum Daily Quantity or (2) the actual quantity of gas that the connecting pipeline upstream of GTN is capable of delivering for Shipper's account to GTN at Shipper's primary point of receipt(s) on GTN less Shipper's requirement to provide compressor fuel and line losses under the Statement of Effective Rates and Charges of GTN's FERC Gas Tariff, Third Revised Volume No. 1-A or (3) the quantity of gas that Pacific Gas And Electric Company (PG&E) is capable of accepting at Malin for Shipper's account or (4) Shipper's nomination to GTN.

The Reservation Charge Credit for each Credit Day for a particular Shipper shall be computed as follows:

Reservation Charge	A		B - C
Credit for Each	-----	x	-----
Credit Day	= (30.4)		(B)

- where A = Shipper's Monthly Reservation Charge
- B = Shipper's confirmed daily nomination for the
 Credit Day
- C = Actual quantity of gas delivered by GTN to PG&E Malin
 for Shipper's account for the Credit Day

Except as provided for in Paragraph 3.11 of this rate schedule, this Reservation Charge Credit is Shipper's sole remedy for nondelivery of gas by GTN.

(Continued)

RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

3.12 Reservation Charge Credit - Other than Malin Primary Delivery Point

If GTN fails to deliver Forward-haul service on a Primary Path to a primary delivery point on its system other than Malin, Oregon, ninety-five percent (95%) or more of the aggregate Confirmed Daily Nominations (as hereinafter defined) of all Shippers at such primary delivery point other than Malin receiving service under this rate schedule (hereinafter referred to as the "Non-Deficiency Amount") for more than twenty-five (25) days in any given Contract Year, then for each day during that Contract Year in excess of twenty-five (25) days that GTN so fails to deliver the Non-Deficiency Amount (a "Credit Day") Shipper, as its sole remedy, shall be entitled to a Reservation Charge Credit calculated in the manner hereinafter set forth.

For the purpose of this Paragraph 3.12, Confirmed Daily Nomination shall mean for any day, the lesser of (1) Shipper's Maximum Daily Quantity or (2) the quantity of gas that the connecting downstream pipeline(s), local distribution company pipeline(s), or end-user(s) is/are capable of accepting for Shipper's account at Shipper's point(s) of primary delivery on GTN or (3) the quantity of gas that the connecting pipeline upstream of GTN is capable of delivering to GTN for Shipper's account to GTN at Shipper's primary point of receipt(s) on GTN less Shipper's requirement to provide compressor fuel and line losses under the Statement of Effective Rates and Charges of GTN's FERC Gas Tariff, Third Revised Volume No. 1-A or (4) Shipper's nomination to GTN.

The Reservation Charge Credit for each Credit Day for a particular Shipper shall be computed as follows:

Reservation Charge	A		B - C
Credit for Each	-----	x	-----
Credit Day	= (30.4)		(B)

- where A = Shipper's Monthly Reservation Charge
- B = Shipper's confirmed daily nomination for the
 Credit Day
- C = Actual quantity of gas delivered by GTN to a Shipper's
 primary delivery point(s) (other than Malin) for
 Shipper's account for the Credit Day

Except as provided for in Paragraph 3.10 of this rate schedule this Reservation Charge Credit is Shipper's sole remedy for nondelivery of gas by GTN.

(Continued)

Rate Schedule FTS-1 Firm Transportation Service

(Continued)

3. RATES (Continued)

3.13 NEGOTIATED RATES

Notwithstanding any provision of GTN's Tariff to the contrary, GTN and Shipper may mutually agree in writing to a Negotiated Rate (including a Negotiated Rate Formula) with respect to the rates, rate components, charges, or credits that are otherwise prescribed, required, established, or imposed by this Rate Schedule or by any other applicable provision of GTN's Tariff.

Such Negotiated Rate shall be set forth in Attachment B to the Firm Transportation Service Agreement and GTN shall make any filings with the Commission necessary to effectuate such Negotiated Rate.

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RATE SCHEDULE FTS-1
FIRM TRANSPORTATION SERVICE
(Continued)

4. FUEL AND LINE LOSS

For all Forward Hauls, Shipper shall furnish to GTN quantities of gas for compressor station fuel, line loss and other utility purposes, plus other unaccounted for gas used in the operation of GTN's combined pipeline system between the International Boundary near Kingsgate, British Columbia and the Oregon-California boundary for the transportation quantities of gas delivered by GTN to Shipper, based upon the effective fuel and line loss percentages in accordance with Paragraph 37 of the General Terms and Conditions. No fuel charge shall apply to transactions that do not involve a forward haul movement of gas.

5. TRANSPORTATION GENERAL TERMS AND CONDITIONS

All of the Transportation General Terms and Conditions are applicable to this rate schedule, unless otherwise stated in the executed Firm Transportation Service Agreement between GTN and Shipper. Any future modifications, additions or deletions to said Transportation General Terms and Conditions, unless otherwise provided, are applicable to firm transportation service rendered under this rate schedule, and by this reference, are made a part hereof.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

1. DEFINITIONS

- 1.1 Gas Day: In accordance with NAESB Standard 1.3.1, Version 1.5, the term "Gas Day" shall be 9:00 a.m. to 9:00 a.m. Central Clock Time (7:00 a.m. to 7:00 a.m. Pacific Clock Time).
- 1.1.1 Business Day: The term "Business Day" shall mean Monday through Friday, excluding U.S. Federal Banking Holidays for transactions in the United States and similar holidays for transactions occurring in Canada and Mexico.
- 1.2 Month: The word "month" shall mean a period extending from the beginning of the first day in a calendar month to the beginning of the first day in the next succeeding calendar month.
- 1.3 Maximum Daily Quantity: The term "Maximum Daily Quantity" (MDQ) shall mean the maximum daily quantity in Dth of gas which GTN agrees to deliver exclusive of an allowance for compressor station fuel, line loss and other unaccounted for gas and transport for the account of Shipper to Shipper's point(s) of delivery on each day during each year during the term of Shipper's Transportation Service Agreement with GTN.
- 1.4 Marketing Affiliate: The term "marketing affiliate" shall mean Pacific Gas and Electric Company and CEG Energy Options Inc.
- 1.5 Gas: The word "gas" shall mean natural gas.
- 1.6 Cubic Foot of Gas: The term "cubic foot of gas" is defined in accordance with NAESB Standard 2.3.9, Version 1.5, as that quantity of gas which measures one (1) cubic foot at standard conditions of 14.73 dry psia, 60 degrees F. For gas volumes reported in cubic meters, the standard conditions are 101.325 kPa, 15 degrees C. Standard 2.3.9, Version 1.5 states in full "Standardize the reporting basis for Btu as 14.73 psia and 60 degrees F (101.325 kPa and 15 degrees C, and dry). Standardize the reporting basis for gigacalorie as 1.035646 Kg/cm² and 15.6 degrees C and dry. Standardize the reporting basis for gas volumes as cubic foot at standard conditions of 14.73 psia, 60 degrees, F and dry. For gas volumes reported in cubic meters, the standard conditions are 101.325 kPa, 15 degrees C, and dry."
- 1.7 Mcf: The term "Mcf" shall mean one thousand (1,000) cubic feet of gas and shall be measured as set forth in Paragraph 5 hereof. The term "MMcf" shall mean one million (1,000,000) cubic feet of gas.

TRANSPORTATION GENERAL TERMS AND CONDITIONS

1. DEFINITIONS (Continued)

1.8 Dekatherm: The term "Dekatherm" (or "Dth") is the quantity of heat energy equivalent to one million (1,000,000 British Thermal Units (MMBtu)). Dth is the standard quantity for Nominations, confirmations and Scheduled Quantities in the United States. For purposes of this tariff and associated Service Agreements, the terms MMBtu and Dth are synonymous.

1.9 Btu: The term "Btu" shall mean British Thermal Unit. The term "MMBtu" shall mean one million (1,000,000) British Thermal Units. The reporting basis for Btu shall be standardized as 14.73 dry psia and 60 degrees (60o) Fahrenheit (101.325 kPa and 15.6 degrees C).

1.10 Gross Heating Value. The term "gross heating value" shall mean the number of Btus in a cubic foot of gas at a temperature of sixty degrees (60o) Fahrenheit, saturated with water vapor, and at an absolute pressure equivalent to thirty (30) inches of mercury at thirty-two degrees (32o) Fahrenheit.

1.11 Psig. The term "psig" shall means pounds per square inch gauge.

1.12 Releasing Shipper: A firm transportation Shipper which intends to post its service to be released to a Replacement Shipper, has posted the service for release, or has released its service.

1.13 Replacement Shipper: A Shipper which has contracted to utilize a Releasing Shipper's service for a specified period of time.

1.14 Posting Period: The period of time during which a Releasing Shipper may post, or have posted by the pipeline, all or a part of its service for release to a Replacement Shipper.

1.15 Release Term: The period of time during which a Releasing Shipper intends to release, or has released all or a portion of its contracted quantity of service to a Replacement Shipper.

(Continued)

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

1. DEFINITIONS (Continued)

1.16 Bid Period: The period of time during which a Replacement Shipper may bid to contract for a parcel which has been posted for release by a Releasing Shipper.

1.17 Parcel: The term utilized to describe an amount of capacity, expressed in Dth/d, from a specific receipt point to a specific delivery point for a specific period of time which is released and bid on pursuant to the capacity release provisions contained in Paragraph 28 of these Transportation General Terms and Conditions.

1.18 Primary Release: The term used to describe the release of capacity by a Releasing Shipper receiving service under a Part 284 firm transportation rate schedule.

1.19 Secondary Release: The term used to describe the release of capacity by a Replacement Shipper receiving service under a Part 284 firm transportation rate schedule.

1.20 Bid Reconciliation Period: The period of time subsequent to the Bid Period during which bids are evaluated by GTN.

1.21 Match Period: The period of time subsequent to the Bid Reconciliation Period and before the notification deadline for awarding capacity for Prearranged Deal C during which the Prearranged Shipper may match any higher bids for the Parcel.

1.22 Mainline Facilities: The term "Mainline Facilities" shall mean the 36-inch and 42-inch mains and appurtenant facilities extending from the interconnection with the pipeline facilities of Alberta Natural Gas Company and Foothills Pipe Lines (South B.C.) Ltd., near Kingsgate, British Columbia to the interconnection with the pipeline facilities of Pacific Gas and Electric Company near Malin, Oregon.

(Continued)

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

1. DEFINITIONS (Continued)

1.23 Extension Facilities: The term "Extension Facilities" shall mean the 12-inch mains and appurtenant facilities extending from GTN's mainline facilities at Milepost 304.25 and the 16-inch and 12-inch mains and appurtenant facilities extending from GTN's Mainline Facilities at Milepost 599.20 that were authorized in Docket No. CP93-618-000. The term "Extension Facility" shall mean one of the Extension Facilities.

1.24 Subject Shipper: The term "Subject Shipper" shall mean the Shippers identified in Appendix G of the Stipulation and Agreement in Docket No. RP94-149-000, et al., and Shippers that have obtained service rights from such Shippers.

1.25 Nominations: A "Nomination" shall be the provision of information to GTN necessary to effectuate a transportation transaction. Specific Nomination procedures are set forth in Section 19.4 of the General Terms and Conditions of Transporter's FERC Gas Tariff.

1.26 Intraday Nomination: An "Intraday Nomination" is a Nomination submitted after the Nomination deadline whose effective time is no earlier than the beginning of the Gas Day and runs through the end of the Gas Day.

1.27 Gas Industry Standards Board Standards: The term "Gas Industry Standards Board Standards" or "GISB Standards" shall mean the standardized business practices and electronic communication practices promulgated by the Gas Industry Standards Board from time to time and incorporated in the Code of Federal Regulations by the Federal Energy Regulatory Commission.

1.28 CES Capacity: The term "CES Capacity" shall mean the additional firm capacity on GTN's Mainline Facilities between the northernmost point near Kingsgate, British Columbia, and points downstream thereof that was made available for subscription on a firm basis as a result of the expansion of GTN's system authorized in Docket No. CP98-167.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

1. DEFINITIONS (Continued)

1.29 Forward Haul: The term "Forward Haul" shall refer to transportation service on GTN's system in which the nominated direction of flow from receipt point to delivery point is in the same direction as physical gas flow on the GTN system.

1.30 Backhaul: The term "Backhaul" shall refer to transportation service on GTN's system in the opposite direction of a Forward Haul as defined in Section 1.29 above.

1.31 Primary Path: The term "Primary Path" shall mean the transportation path established by the receipt and delivery points as set forth in Shipper's executed Service Agreement. A shipper's Primary Path may be either a Forward Haul or a Backhaul as defined in Sections 1.29 and 1.30 above.

1.32 Reverse Path: The term "Reverse Path" shall mean the transportation path that is in the opposite direction of that Shipper's Primary Path as defined in Section 1.31 above. A shipper's Reverse Path may be either a Forward Haul or a Backhaul as defined in Sections 1.29 and 1.30 above. Reverse Path transactions are subject to the operating conditions of GTN's pipeline and will not be made available to Shipper if GTN determines, in its sole discretion, that such transportation is operationally infeasible or otherwise not available.

1.33 Negotiated Rate. The term "Negotiated Rate" shall mean a rate (including a Negotiated Rate Formula) that GTN and a Shipper have agreed will be charged for service under Rate Schedules FTS-1, LFS-1, ITS-1, AIS-1 or PS-1 where, for all or a portion of the contract term, one or more of the individual components of such rate may exceed the maximum rate, or be less than the minimum rate, for such component set forth in GTN's tariff for the given service. Any Agreement entered into after the effective date of this subsection which provides for a rate under Rate Schedules FTS-1, LFS-1, ITS-1, AIS-1 or PS-1 other than the applicable maximum rate shall contain a provision setting out the mutual agreement of the parties as to whether the pricing terms represent a discounted rate or a negotiated rate.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

1. DEFINITIONS (Continued)

1.34 Negotiated Rate Formula. The term "Negotiated Rate Formula" shall mean a rate formula that GTN and a Shipper have agreed will apply to service under a specific contract under Rate Schedules FTS-1, LFS-1, ITS-1, AIS-1 or PS-1 which results in a rate where, for all or a portion of the contract term, one or more of the individual components of such rate may exceed the maximum rate, or may be less than the minimum rate, for such component set forth in GTN's Tariff for the given service.

1.35 Recourse Rate. The term "Recourse Rate shall mean the applicable maximum rate that would apply to a service but for the rate flexibility allowed under Section 31 of this Gas Tariff.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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2. GAS RESEARCH INSTITUTE CHARGE ADJUSTMENT PROVISION

2.1 Purpose: GTN has joined with other gas enterprises in the formation of, and participation in, the activities and financing of the Gas Research Institute (GRI), an Illinois Not For Profit corporation. GRI has been organized for the purpose of sponsoring Research, Development and Demonstration (RD&D) programs in the field of natural and manufactured gas for the purpose of assisting all segments of the gas industry in providing adequate, reliable, safe, economic and environmentally acceptable gas service for the benefit of gas consumers and the general public.

For the purpose of funding GRI's approved expenditures, this Paragraph 2 establishes a GRI Adjustment Charge to be applicable to GTN's Rate Schedules ITS-1, AIS-1, PS-1 and FTS-1 in this FERC Gas Tariff, Third Revised Volume No. 1-A; provided, however, such charge shall not be applicable in the event gas is delivered to a downstream interstate pipeline that is a member of GRI.

2.2 Basis for the GRI Adjustment Charges: The rate schedule specified in Paragraph 2.1 hereof shall include an increment for a GRI Adjustment Charge for RD&D. Such GRI Adjustment Charge shall be that increment, adjusted to GTN's pressure base and heating value if required, which has been approved by Federal Energy Regulatory Commission Orders approving GRI's RD&D expenditures. The GRI Adjustment Charge shall be reflected in the current Statement of Effective Rates and Charges for Transportation of Natural Gas in this FERC Gas Tariff, Third Revised Volume No. 1-A.

2.3 Filing Procedure: The notice period and proposed effective date of filings pursuant to this paragraph shall be as permitted under Section 4 of the Natural Gas Act; provided, however, that any such filing shall not become effective unless it becomes effective without suspension or refund obligation.

2.4 Remittance to GRI: GTN shall remit to GRI, not later than fifteen (15) days after the receipt thereof, all monies received by virtue of the GRI Adjustment Charge or the Check the Box procedure, less any amounts properly payable to a Federal, State or Local authority relating to the monies received hereunder.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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2. GAS RESEARCH INSTITUTE CHARGE ADJUSTMENT PROVISION (Continued)

2.5 A high load factor Shipper is a Shipper with a load factor greater than fifty (50) percent. A low load factor Shipper is a Shipper with a load factor equal to or less than fifty (50) percent. A Shipper's load factor for each service agreement shall be determined annually using the most recent twelve (12) months of actual throughput available (including throughput using capacity released pursuant to Paragraph 28 of the Transportation General Terms and Conditions). The Shipper's load factor shall remain in effect during the calendar year. In the event twelve (12) months of actual data does not exist, the Shipper's load factor shall be determined monthly based on the latest recorded throughput data. The appropriate GRI demand surcharge is applied monthly until such time as twelve (12) months of actual data is accumulated. At such time the Shipper's load factor shall remain in effect during the calendar year.

2.6 For the purpose of funding GRI's approved expenditures, and subject to the further terms and conditions set forth in the Stipulation and Agreement Concerning the Post-1993 GRI Funding Mechanism and the orders approving such Stipulation and Agreement found at Gas Research Institute, 62 FERC P. 61,316

(1993) this Paragraph 2 establishes a GRI Funding Unit which shall be collected for quantities of gas transported under GTN's rate schedules provided, however, such charge shall not be applicable to discounted transactions except where the discounted rate is less than the GRI Funding Unit. In this instance GTN shall remit that portion of the GRI Funding Unit actually collected. For purposes of discounted transactions, any GRI Funding Unit shall be considered to be the first component of rates discounted. The GRI Funding Unit may be discounted to zero and shall not be applied to the same quantity of gas more than once.

2.7 Voluntary GRI Contributions. GTN has agreed to be a collection agent for shippers that voluntarily choose to support GRI through a "check the box" procedure on GTN's invoices. Amounts collected will be remitted to GRI in accordance with the requirements of Section 2.4 of this FERC Gas Tariff. The amounts collected pursuant to this procedure will not be part of GTN's rates.

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3. QUALITY OF GAS

3.1 Quality Standards: The gas which Shipper delivers hereunder to GTN for transport (and the gas which GTN transports hereunder for Shipper) shall be merchantable gas at all times complying with the following quality requirements:

(a) Heating Value: The gas shall have a gross heating value of not less than nine hundred ninety-five (995) Btus per standard cubic foot on a dry basis, but with the consent of Shipper, GTN may deliver gas at a lower gross heating value.

(b) Freedom from Objectionable Matter: The gas:

(1) Shall be commercially free from sand, dust, gums, crude oil, impurities and other objectionable substances which may be injurious to pipelines or which may interfere with its transmission through pipelines or its commercial utilization.

(2) Shall not have a hydrocarbon dew-point in excess of fifteen degrees (15m) Fahrenheit at pressures up to eight hundred (800) psig.

(3) Shall not contain more than one-quarter (1/4) grain of hydrogen sulfide per one hundred (100) standard cubic feet.

(4) Shall not contain more than ten(10) grains of total sulphur per one hundred (100) standard cubic feet.

(5) Shall not contain more than two percent (2%) by volume of carbon dioxide.

(6) Shall not contain more than four (4) pounds of water vapor per one million (1,000,000) standard cubic feet.

(7) Shall not exceed one hundred ten degrees
(110m) Fahrenheit in temperature at the point of measurement.

(8) Shall be as free of oxygen as it can be kept through the exercise of all reasonable precautions, and shall not in any event contain more than four-tenths of one percent (0.4%) by volume of oxygen.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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3. QUALITY OF GAS (Continued)

3.2 Quality Tests:

(a) The quality specifications of the gas received by GTN hereunder shall be determined by tests which GTN shall cause to be made at the International Boundary or such other locations on GTN's system if required accordance with this Paragraph 3.2.

(b) The gross heating value of gas delivered hereunder shall be determined from read-outs of continuously operating measuring instruments. The method shall consist of one or more of the following:

(1) calorimeter

(2) gas chromatograph

(3) any other method mutually agreed upon by the parties.

Measurement of gross heating value with the calorimeters shall comply with the standards set forth in the American Society for Testing and Materials' ASTM D 1826. Analysis of gas with gas chromatograph shall comply with the standards set forth in ASTM D 1945. Calculation of the gross heating value from compositional analysis by gas chromatography shall comply with the standards set forth in ASTM D 3588.

GTN or its agent shall calibrate and maintain the gross heating value measurement device at intervals as agreed upon by GTN and Shipper. Shipper shall have access to GTN's devices and shall be allowed to inspect the devices and all charts or other records of measurement at any reasonable time.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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3. QUALITY OF GAS (Continued)

3.2 Quality Tests (Continued)

(c) Tests shall be made to determine the total sulphur, hydrogen sulfide, carbon dioxide and oxygen content of the gas, by approved standard methods in general use in the gas industry, and to determine the hydrocarbon dew-point and water vapor content of such gas by methods satisfactory to the parties. Tests shall be made frequently enough to ensure that the gas is conforming continuously to the quality requirements. Shipper shall have the right to require GTN to have remedied any deficiency in quality of the gas and, in the event such deficiency is not remedied, the right, in addition to all other remedies available to it by law, to refuse to accept such deficient gas until such deficiency is remedied.

4. MEASURING EQUIPMENT

4.1 Installation: Unless GTN and Shippers agree otherwise, all gas volume measuring equipment, devices and materials at the point(s) of receipt and/or delivery shall be furnished and installed by GTN at Shipper's expense including the tax-on-tax effect. All such equipment, devices and materials shall be owned, maintained and operated by GTN. Shipper may install and operate check measuring equipment provided it does not interfere with the use of GTN's equipment.

4.2 Testing Meter Equipment: The accuracy of either GTN's or Shippers measuring equipment shall be verified by test, using means and methods acceptable to the other party, at intervals mutually agreed upon, and at other times upon request. Notice of the time and nature of each test shall be given by the entity conducting the test to the other entity sufficiently in advance to permit convenient arrangement for the presence of the representative of the other entity. If, after notice, the other entity fails to have a representative present, the results of the test shall nevertheless be considered accurate until the next test. If any of the measuring equipment is found to be registering inaccurately in any percentage, it shall be adjusted at once to read as accurately as possible. All tests of such measuring equipment shall be made at the expense of the entity conducting the same, except that the other entity shall bear the expense of tests made at its request if the inaccuracy is found to be two percent (2%) or less.

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4. MEASURING EQUIPMENT (Continued)

4.3 Correction and Adjustment: If at any time any of the measuring equipment is registering inaccurately by an amount exceeding two percent (2%) at a reading corresponding to the average hourly rate of flow, the previous readings of such equipment shall be corrected to zero error for any period definitely known or agreed upon, or if not so known or agreed upon, the lesser of one-half (1/2) of the elapsed time since the last test or six months from the production month with a three-month rebuttal period, provided, however, that this limitation shall not apply in the case of a deliberate omission or misrepresentation or mutual mistake of fact. The parties' other statutory or contractual rights shall not otherwise be diminished by this limitation. If the measuring equipment is out-of-service, the volume of gas delivered during such period shall be determined:

(a) By using the data recorded by any check measuring equipment accurately registering; or

(b) If such check measuring equipment is not registering accurately but the percentage of error is ascertainable by a calibration test, by using the data recorded, corrected to zero error; or

(c) If neither of the methods provided in (a) and (b) above can be used, by estimating the quantity delivered, by reference to deliveries under similar conditions during a period when the equipment was registering accurately.

No correction shall be made in the recorded volumes of gas delivered hereunder for measuring equipment inaccuracies of two percent (2%) or less, and in no event shall inaccuracies less than 25 Mcf be considered for adjustment.

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5. MEASUREMENTS

5.1 Metering: The gas shall be metered by one or more orifice, turbine, ultrasonic, displacement or other-type meters, at the discretion of GTN. All meters shall be installed and maintained, and volumes shall be measured, in accordance with applicable A.G.A. standards for the meter in question.

5.2 Specific Gravity: The specific gravity of the gas delivered hereunder shall be determined from the read-outs of continuously operating measuring instruments. The method shall consist of one of the following:

(a) gravitometer

(b) gas chromatography

(c) other instruments acceptable to both parties

Analysis of chromatograph shall comply with the standards set forth in ASTM D 1945. Calculation of the specific gravity from compositional analysis by gas chromatography shall comply with the standards set forth in ASTM D 3588. Measurement of the specific gravity with a gravitometer shall comply with the standards set forth in ASTM D 1070.

5.3 Flowing Temperature: Flowing gas temperature shall be continuously measured and used in flow calculations.

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6. INSPECTION OF EQUIPMENT AND RECORDS

6.1 Inspection of Equipment and Data: GTN and Shipper shall have the right to inspect equipment installed or furnished by the other, and the charts and other measurement or test data of the other, at all times during business hours; but the reading, calibration and adjustment of such equipment and changing of charts shall be done only by the entity installing or furnishing same. Unless GTN and Shipper otherwise agree, each shall preserve all original test data, charts and other similar records in such party's possession, for a period of at least six (6) years.

6.2 Information for Billing: When information necessary for billing by GTN is in the control of Shipper, Shipper shall furnish such information, estimated if actual is not available, to GTN on or before the third (3rd) working day of the month following the month transportation service was rendered. If shipper furnishes estimated information, the actual information shall be furnished to GTN on or before the fifth (5th) working day of the month following the month transportation service was rendered.

6.3 Verification of Computations: GTN and Shipper shall have the right to examine at reasonable times the books, records and charts of the other to the extent necessary to verify the accuracy of any statement, charge or computation made pursuant to these Transportation General Terms and Conditions and to the rate schedules to which they apply, within twelve (12) months of any such statement, charge or computation. The time limitation for disputing allocations shall be six (6) months from the date of initial month-end allocation with a three-month rebuttal period, provided, however, that this limitation shall not apply in the case of a deliberate omission or misrepresentation or mutual mistake of fact, and shall not diminish the parties' other statutory or contractual rights. In accordance with NAESB Standard 2.3.11, Version 1.5, a meter adjustment or correction becomes a prior period adjustment after the fifth (5th) business day following the Business Month. Any measurement of prior period adjustments are taken back to the production month. These provisions are in accordance with NAESB Standard 2.3.7, Version 1.5, which establishes a cutoff for the closing of measurement of 5 business days after business month.

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6. INSPECTION OF EQUIPMENT AND RECORDS (Continued)

6.3 Verification of Computations: (Continued)

In accordance with NAESB Standard 2.3.14, Version 1.5, measurement data corrections should be processed within 6 months of the production month with a 3-month rebuttal period. However, it is recognized that this latter standard shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contractual rights shall not be diminished by this standard.

7. BILLING

7.1 Billing under all Rate Schedules: On or before the ninth (9th) business day of each month, GTN shall render a bill to each Shipper under all applicable Rate Schedules for the service(s) rendered during the preceding month, which is in accordance with NAESB Standard 3.3.14, Version 1.5, which provides that the imbalance statement should be rendered prior to or with the invoice, and the transportation invoice should be prepared on or before the 9th business day after the end of the production month. Rendered is defined as postmarked, time-stamped, and delivered to the designated site.

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8. PAYMENT

8.1 Payment under all Rate Schedules: On or before the tenth day following the date GTN's bill is rendered in accordance with Paragraph 7.1 of these General Terms and Conditions, each Shipper under all applicable Rate Schedules shall pay to or upon the order of GTN in lawful money of the United States at GTN's office in Portland, Oregon, the amount of the bill rendered by GTN. In accordance with NAESB Standard 3.3.17, Version 1.5, party making payment should submit supporting documentation; party receiving payment should apply payment per supporting documentation provided by the paying party; and if payment differs from invoiced amount, remittance detail should be provided with the payment except when payment is made by electronic funds transfer (EFT), in which case, the remittance detail is due within two Business Days of the payment due date. Shipper shall identify invoice numbers on all payments. In the event a Shipper disputes any portion of the invoice, Shipper shall pay that portion of the invoice not in dispute and provide supporting documentation identifying the basis for the dispute.

8.2 Interest on Unpaid Amounts: Should Shipper fail to pay the amount of any bill rendered by GTN when such amount is due, interest thereon shall accrue from the due date until paid at the rate of interest effective from time to time under 18 CFR Section 154.67.

8.3 Remedies for Failure to Pay: If a Shipper's failure to pay the undisputed portion of an invoice continues for thirty (30) days after payment is due, GTN, in addition to any other remedy it may have, may suspend further delivery of gas until such amount is paid.

If Shipper's failure to pay extends beyond thirty (30) days after payment is due, in addition to suspending service under Shipper's Transportation Service Agreement(s), Transporter shall have the right to terminate service. To the extent that Transporter seeks to terminate a Shipper's Transportation Service Agreement, Transporter will provide written notice to Shipper, the Commission, and any Replacement Shipper(s) that has obtained temporary release capacity from Shipper, that if Shipper fails to make payment within fifteen (15) days, Transporter will terminate Shipper's Transportation Service Agreement(s) and may exercise any other remedy available to Transporter hereunder, at law or in equity.

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8. PAYMENT (Continued)

8.3 Remedies for Failure to Pay: (Continued)

However, if Shipper, in good faith, disputes the amount of any bill or part thereof by providing written notice of its dispute including documentation identifying the basis of the dispute and 1) promptly pays to Transporter the undisputed amount, and 2) furnishes to Transporter a good and sufficient letter of credit in an amount and with surety satisfactory to Transporter, or provides other assurance acceptable to Transporter guaranteeing payment to Transporter of the amount ultimately found due upon the bill after a final determination that may be reached either by agreement or by judgement of the courts, as may be the case, then Transporter shall not be entitled to automatically suspend or terminate service under the Transportation Service Agreement(s) unless and until a default is made in the conditions of the letter of credit or other assurance; provided further that should Shipper prevail on the dispute, Transporter shall reimburse Shipper up to the reasonable and customary costs of the letter of credit or other assurance provided.

8.4 Late Billing: If presentation of a bill by GTN is delayed after the date specified in Paragraph 7.1 hereof, then the time for payment shall be extended correspondingly unless Shipper is responsible for such delay.

8.5 Adjustment of Billing Error: In accordance with NAESB Standard 3.3.15, Version 1.5, prior period adjustment time limits should be 6 months from the date of the initial transportation invoice and 7 months from date of initial sales invoice with a 3-month rebuttal period, excluding government-required rate changes. This standard shall not apply in the case of deliberate omission or misrepresentation or mutual mistake of fact. Parties' other statutory or contractual rights shall not otherwise be diminished by this standard.

9. NOTICE OF CHANGES IN OPERATING CONDITIONS

GTN and Shipper shall each ensure that the other is notified from time to time as necessary of expected changes in the rates of delivery or receipt of gas, or in the pressures or other operating conditions, and the reason for such expected changes, so that they may be accommodated when they occur.

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10. FORCE MAJEURE

10.1 If either party shall fail to perform any obligation imposed upon it by these Transportation General Terms and Conditions or by an executed Transportation Service Agreement, and such failure shall be caused, or materially contributed to, by force majeure which means any acts of God, strikes, lockouts, or other industrial disturbances, acts of public enemies, sabotage, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, floods, storms, fires, washouts, extreme cold or freezing weather, arrests and restraints of rulers and people, civil disturbances, explosions, breakage of or accident to machinery or lines of pipe, hydrate obstructions of lines of pipe, inability to obtain pipe, materials or equipment, legislative, administrative or judicial action which has been resisted in good faith by all reasonable legal means, any acts, omissions or causes whether of the kind herein enumerated or otherwise not reasonably within the control of the party invoking this paragraph and which by the exercise of due diligence such party could not have prevented, the necessity for making repairs to, replacing, or reconditioning machinery, equipment, or pipelines not resulting from the fault or negligence of the party invoking this paragraph, such failure shall be deemed not to be a breach of the obligation of such party, but such party shall use reasonable diligence to put itself in a position to carry out its obligations. Nothing contained herein shall be construed to require either party to settle a strike or lockout by acceding against its judgment to the demands of the opposing parties.

10.2 No such cause as described in Paragraph 10.1 affecting the performance of either party shall continue to relieve such party from its obligation after the expiration of a reasonable period of time within which by the use of due diligence such party could have remedied the situation preventing its performance, nor shall any such cause relieve either party from any obligation unless such party shall give notice thereof in writing to the other party with reasonable promptness; and like notice shall be given upon termination of such cause.

10.3 No cause whatsoever, including without limitation the failure of GTN to perform including the causes specified in Paragraph 10.1, shall relieve Shipper from its obligations to make payments due, including the payments of reservation charges for the duration of such cause except as provided for in Paragraphs 3.10 and 3.11 of Rate Schedule FTS-1.

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11. WARRANTY OF ELIGIBILITY FOR TRANSPORTATION

Any Shipper transporting gas on the GTN system under this FERC Gas Tariff, Third Revised Volume No. 1-A warrants for itself, its successors and assigns, that it will have at the time of delivery of the gas to GTN hereunder good title to such gas and that all gas delivered to GTN for transportation hereunder is eligible for the requested transportation in interstate commerce under applicable rules, regulations or orders of the FERC, or other agency having jurisdiction. Shipper will indemnify GTN and save it harmless from all suits, actions, damages, costs, losses, expenses (including reasonable attorney fees) costs connected with regulatory proceedings, arising from breach of this warranty.

12. POSSESSION OF GAS AND RESPONSIBILITY

GTN shall be deemed to be in control and possession of, and responsible for, all gas delivered from the time that such gas is received by it at the point of receipt to the time that it is delivered at the point of delivery.

13. INDEMNIFICATION

Shipper agrees to indemnify and hold harmless GTN, its officers, agents, employees and contractors against any liability, loss or damage whatsoever occurring in connection with or relating in any way to the executed Transportation Service Agreement, including costs and attorneys' fees, whether or not such liability, loss or damage results from any demand, claim, action, cause of action, or suit brought by Shipper or by any person, association or entity, public or private, that is not a party to the executed Transportation Service Agreement, where such liability, loss or damage is suffered by GTN, its officers, agents, employees or contractors as a direct or indirect result of any breach of the executed Transportation Service Agreement or sole or concurrent negligence or gross negligence or other tortious act(s) or commission(s) by Shipper, its officers, agents, employees or contractors.

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14. ARBITRATION

Any arbitration provided for or agreed to by Shipper and GTN shall be conducted in accordance with the following procedures and principles: Upon the written demand of either GTN or Shipper and within ten (10) days from the date of such demand, each entity shall appoint an arbitrator and the two arbitrators so appointed shall promptly thereafter appoint a third. If either GTN or Shipper shall fail to appoint an arbitrator within ten (10) days from the date of such demand, then the arbitrator shall be appointed by a Superior Court of the State of California in accordance with the California Code of Civil Procedure. If the two arbitrators shall fail within ten (10) days from their appointment to agree upon and appoint the third arbitrator, then upon the application of either GTN or Shipper such third arbitrator shall be appointed by a Superior Court of the State of California in accordance with the California Code of Civil Procedure.

The arbitrators shall proceed immediately to hear and determine the matter in controversy. The award of the arbitrators, or a majority of them, shall be made within forty-five (45) days after the appointment of the third arbitrator, subject to any reasonable delay due to unforeseen circumstances. The award of the arbitrators shall be drawn up in writing and signed by the arbitrators, or a majority of them, and shall be final and binding on both GTN and Shipper, and GTN and Shipper shall abide by the award and perform the terms and conditions thereof. Unless otherwise determined by the arbitrators, the fees and expenses of the arbitrator named for each party shall be paid by that party and the fees and expenses of the third arbitrator shall be paid in equal proportion by both GTN and Shipper.

15. GOVERNMENTAL REGULATIONS

These Transportation General Terms and Conditions, the rate schedules to which they apply, and any executed Transportation Service Agreement are subject to valid laws, orders, rules and regulations of duly constituted authorities having jurisdiction.

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16. MISCELLANEOUS PROVISION

16.1 Waiver of Default: No waiver by either GTN or Shipper of any default by the other in the performance of any provisions of an executed Transportation Service Agreement shall operate as a waiver of any continuing or future default, whether of a like or different character.

16.2 Assignability: An executed Transportation Service Agreement shall bind and inure to the respective successors and assignees of GTN and Shipper thereto, but no assignment shall release either party thereto from such party's obligations without the written consent of the other party, which consent shall not be unreasonably withheld; provided, however, nothing contained herein shall give Shipper the right to reassign or broker its right to ship the quantities of gas specified in the Transportation Service Agreement on GTN's system to others. Further, nothing contained herein shall prevent either party from pledging, mortgaging or assigning its rights as security for its indebtedness and either party may assign to the pledgee or mortgagee (or to a trustee for the holder of such indebtedness) any money due or to become due under any service agreement.

16.3 Effect of Headings: The headings used throughout these Transportation General Terms and Conditions, the rate schedules to which they apply, and the executed Transportation Service Agreements are inserted for reference purposes only and are not to be considered or taken into account in construing the terms and provisions of any paragraph nor to be deemed in any way to qualify, modify or explain the effects of any such terms or provisions.

17. TRANSPORTATION SERVICE AGREEMENT

17.1 Form: Shipper shall enter into a contract with GTN utilizing GTN's appropriate standard form of Transportation Service Agreement.

17.2 Term: The term of the Transportation Service Agreement shall be agreed upon between Shipper and GTN at the time of the execution thereof.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

18 OPERATING PROVISIONS

18.0 Requests For Service:

(A) A prospective shipper desiring service on GTN's system must fully complete the Service Request Form set out in GTN's EBB. Alternatively, a prospective shipper may request a hard-copy of the Service Request Form by contacting GTN's Service and Contract Coordinator at the following location:

Gas Transmission Northwest Corporation Services and Contract Coordinator 1400 SW Fifth Avenue, Suite 900 Portland, OR 97201
Phone: 503/833-4300, Option 2

(B) If Shipper requests service under Section 311(a), Shipper must provide a certification that the service qualifies under 18 C.F.R. Section 284.102. To enable GTN to verify that the requested transportation service will qualify under 18 C.F.R. Section 284.102, the certification must provide facts showing that:

(a) the "On Behalf Of" party will have physical custody of and transport the natural gas at some point; or

(b) the "On Behalf Of" party will hold title to the natural gas at some point, which may occur prior to, during, or after the time that the gas is transported by GTN, for a purpose related to the "On Behalf Of" party's status and function as an intrastate pipeline or its status and function as a local distribution company; or

(c) the gas will be delivered to a customer that is either located in the "On Behalf Of" party's service area, if the "On Behalf Of" party is a local distribution company, or is physically able to receive direct deliveries of gas from the "On Behalf Of" party, if the "On Behalf Of" party is an interstate pipeline, and that "On Behalf Of" party has certified that it is on its behalf that GTN will be providing the requested transportation service.

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18 OPERATING PROVISIONS (Continued)

18.0 Requests For Service (Continued)

(C) Submission of this Service Request Form will allow GTN to begin processing Shipper's Request For Service, but does not guarantee service will be available. GTN will not provide service until Shipper has executed a service contract. Shipper also shall be required to meet other provisions of this FERC Gas Tariff, including the credit requirements set out in Section 18.3 of this Tariff. Standard form service contracts for each service offered by GTN are set out in the Form of Service Agreement portion of this Tariff.

Shipper shall not be entitled to receive transportation service under this FERC Gas Tariff, Third Revised Volume No. 1-A if Shipper is not current in its payments to GTN for any charge, rate or fee authorized by the Commission for transportation service; provided, however, if the amount not current pertains to a bona fide dispute, including but not limited to force majeure claims relating to this FERC Gas Tariff, Shipper shall be entitled to receive or continue to receive transportation service if Shipper posts a bond satisfactory to GTN to cover the payment due GTN.

18.1 Firm Service

The provisions of this Paragraph 18.1 shall be applicable to firm transportation service under Rate Schedules FTS-1 and LFS-1 contained in this Third Revised Volume No. 1-A. Firm transportation service under this Third Revised Volume No. 1-A shall be provided when, and to the extent that, GTN determines that firm capacity is available on GTN's existing facilities. GTN shall not be required to provide firm transportation service in the event firm capacity is unavailable or to construct new facilities to provide firm service.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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18. OPERATING PROVISIONS (Continued)

18.1 Firm Service (Continued)

For capacity that becomes available other than through the circumstances identified in Paragraphs 28 and 33, requests for firm capacity shall be accommodated in the following manner and subject to the following conditions and limitations:

(a) In order to be eligible for firm capacity, a party requesting service (requestor) must be deemed credit-worthy per Paragraph 18.3 and submit a valid request in accordance with the provisions herein.

(b) Pre-Arranged Capacity: GTN may enter into a pre-arranged service agreement with any party for available unsubscribed capacity or capacity that will become available and is not subject to a right of first refusal; provided that GTN will post the terms of the pre-arranged transaction and other parties will have an opportunity to bid on the capacity. One year prior to the commencement date of a pre-arranged agreement, GTN will post a notice on its website that the pre-arranged capacity will be subject to the bidding process. GTN will commence open bidding no later than 3 months prior to the in-service date of the pre-arranged agreement. If another party submits a bid with a higher incremental economic value, the pre-arranged Shipper will have a one-time right to match the higher bid in order to retain the capacity. If the pre-arranged Shipper elects not to match a higher competing bid, the capacity will be awarded to the highest creditworthy bidder in accordance with Paragraph 18.1(e). If there is an open season ongoing for certain capacity, GTN will not enter into a pre-arranged deal for that capacity during the open season.

GTN will not enter into pre-arranged service agreements with commencement dates more than three years, or thirty-six months, into the future. GTN will separately identify on its Internet website all capacity that is anticipated to become available within the next thirty-six months. GTN will not enter into any pre-arranged deals for capacity that has not previously been posted on its Internet website.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS

18. OPERATING PROVISIONS (Continued)

18.1 Firm Service (Continued)

(c) Available Capacity:

GTN will post available capacity on its Internet website. A requestor that submits a valid request may submit a bid via the website for the available capacity subsequent to GTN's posting of such capacity on the website. The Bid Period will be a minimum of 1 business day for capacity available for up to 1 month; a minimum of 3 business days for capacity available for greater than one month but less than one year; and a minimum of 5 business days for capacity available for one year or more. All bids not withdrawn prior to the close of the Bidding Period shall be binding. At the end of the Bidding Period, GTN will evaluate the bids and determine the bid(s) having the greatest economic value as determined in Paragraph 18.1(e).

If GTN determines that no bids satisfy the open season criteria, GTN will post the capacity on its website as available unsubscribed capacity. GTN will award such capacity on a first-come, first-served basis to shippers that offer the maximum recourse rate or an acceptable discounted or negotiated rate.

In addition to posting all currently available capacity, GTN will separately identify on its Internet website all capacity that is anticipated to become available within the next thirty-six months.

(d) After the close of the Bidding Period, GTN may tender a Service Agreement for execution to the requestor(s) submitting the bid(s) having the greatest economic value for the capacity available, subject to the provisions of Paragraph 18.1(f).

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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18. OPERATING PROVISIONS (Continued)

18.1 Firm Service (Continued)

(e) Valuation of Bids

Unless otherwise specified in its open season posting, the bid(s) with the greatest economic value will be the bid(s) with the highest net present value ("NPV") based on the reservation charge and any proposed usage charge revenues guaranteed by a minimum volume commitment or otherwise that requestor(s) would pay at the rates the requestor(s) has bid, over the term of service specified in the request. If the economic values of separate bids are equal, then service shall be offered to such requestors on a pro-rata basis. The NPV is the discounted cash flow of the bid according to the following formula, net of revenues lost or affected by the requests for service:

$$\text{Present Value per} = P * R * \frac{(1 + i)(n) - 1}{i(1 + i)(n)}$$

where: P = percent of the rate or charge that the Shipper is willing to pay.

R = Rate or charge calculated as: The applicable maximum authorized reservation charge(s) per Dth in effect at the time of the bid for service.

i = FERC's annual interest rate divided by 12.

n = number of periods for which the bidder wishes to contract.

The NPV formula will be affected by the term and rate requested. In the event GTN intends to entertain bids for service under index-based or other Negotiated Rate Formulae, the future value of which cannot be determined at the time of the bidding, GTN shall estimate the future revenues to be received under the Negotiated Rate Formula using currently available data.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

18. OPERATING PROVISIONS (Continued)

18.1 Firm Service (Continued)

(e) Valuation of Bids (Continued)

The specific bid evaluation methodology to be used, including, where appropriate, the data to be used for evaluation of Negotiated Rate Formula bids, will be included as part of GTN's open season posting under Paragraph 18.1(c) with sufficient specificity to allow a prospective shipper to calculate the value of its bid and duplicate GTN's results.

Irrespective of whether a bid(s) has the highest NPV of the bids received, GTN may reject bids for service that (i) may detrimentally impact the operational integrity of Transporter's system; (ii) do not satisfy all the terms of the specified posting; or (iii) contain terms and conditions other than those set forth in GTN's FERC Gas Tariff.

If the NPV of any Negotiated Rate revenues would exceed the NPV of the revenue stream produced by paying the Maximum Rate over the same period of time, then the Shipper bidding the Negotiated Rate shall be considered to be paying the Maximum Rate for purposes of determining the bid with the greatest economic value.

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18. OPERATING PROVISIONS (Continued)

18.1 Firm Service (Continued)

(f) If GTN accepts the winning bid(s) and tenders a Service Agreement, requestor(s) shall complete and return the Service Agreement within thirty (30) days.

(g) Except as provided in Paragraph 28, GTN shall not be obligated to tender or execute a Service Agreement for service at any rate less than the Maximum Rate set forth in the Statement of Effective Rates and Charges applicable to the service requested.

(h) A Shipper receiving service under FTS-1 shall not lose its priority for purposes of Paragraph 19 by the renewal or extension of term of that service; provided, however, any renewal or extension must be pursuant to a rollover or evergreen provision of the Service Agreement. Shipper's preexisting priority shall not apply, however, to any increase in transportation quantity or new primary point of delivery.

18.2 Interruptible Service

The provisions of this Paragraph 18.2 shall be applicable to interruptible transportation service under Rate Schedule ITS-1 contained in this Third Revised Volume No. 1-A.

(a) Interruptible transportation service under this Third Revised Volume No. 1-A shall be provided when, and to the extent that, capacity is available in GTN's existing facilities, which capacity is not subject to a prior claim under a pre-existing agreement pursuant to Rate Schedule FTS-1 or under another class of firm service.

(b) In the event where natural gas tendered by Shipper to GTN at the receipt point(s) for transportation, or delivered by GTN to Shipper (or for Shipper's account) at the delivery point(s), is commingled with other natural gas at the time of measurement, the determination of deliveries applicable to Shipper shall be made in accordance with operating arrangements satisfactory to Shipper, GTN and any third party transporting to or from GTN's system.

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18. OPERATING PROVISIONS (Continued)

18.2 Interruptible Service (Continued)

(c) GTN shall process requests for interruptible transportation service on a non-discriminatory basis. Available interruptible capacity shall be allocated by GTN first to the Shipper(s) paying the highest rate, followed by a pro-rata tie breaker, as provided for in Paragraph 19 of these General Terms and Conditions.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

18. OPERATING PROVISIONS (Continued)

18.3 Credit-worthiness

(A) Credit-worthiness for Firm Transportation Service

(1) GTN shall not be required to perform or to continue transportation service under this FERC Gas Tariff, Third Revised Volume 1-A on behalf of any Shipper who is or has become insolvent or who, after GTN's request, fails within a reasonable period to establish or confirm credit-worthiness. Shippers shall provide, initially and on a continuing basis, financial statements, evidence of debt and/or credit ratings, and other such information as is reasonably requested by GTN to establish or confirm Shipper's qualification for service. Credit limits will be established based on the level of requested service and Shipper credit-worthiness as established by the following:

(a) Credit-worthiness must be evidenced by at least a long term bond (or other senior debt) rating of BBB or an equivalent rating.

Such rating may be obtained in one of three ways:

(i) The rating will be determined by Standard and Poors or another recognized U.S. or Canadian debt rating service;

(ii) If Shipper's debt is not rated by a recognized debt rating service, an equivalent rating as determined by GTN, based on the financial rating methodology, criteria and ratios for the industry of the Shipper as published by the above rating agencies from time to time. In general, such equivalent rating will be based on the audited financial statements for the Shipper's two most recent fiscal years, all interim reports, and any other relevant information;

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18. OPERATING PROVISIONS (Continued)

18.3 (A) Credit-worthiness for Firm Transportation Service (Continued)

(iii) Shipper may, at its own expense, obtain a private rating from a recognized debt rating service, or request that an independent accountant or financial advisor, mutually acceptable to GTN and the Shipper, prepare an equivalent evaluation based on the financial rating methodology, criteria, and ratios for the industry of the Shipper as published by the above rating agencies from or

(b) Approval by GTN's lenders; or

(c) If Shipper is requesting credit to bid on a parcel that is for one year (365 days) or less of service through GTN's Capacity Release Program contained in Paragraph 28, and this option is selected by the Releasing Shipper, Shipper may demonstrate credit-worthiness by providing two years of audited financial statements for itself, or for its parent company if it is a subsidiary which is consolidated with its parent company and does not issue stand-alone financial statements, demonstrating adequate financial strength to justify the amount of credit to be extended. GTN shall apply consistent evaluation practices to determine credit-worthiness.

(2) If Shipper does not establish or maintain credit-worthiness as described above, Shipper has the option of receiving transportation service under this FERC Gas Tariff by providing to GTN one of the following alternatives:

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18. OPERATING PROVISIONS (Continued)

18.3 (A) Credit-worthiness for Firm Transportation Service (Continued)

(a) A guarantee of Shipper's financial performance in a form satisfactory to GTN and for the term of the Gas Transportation Agreement from a corporate affiliate of the Shipper or a third party either of which meets the credit-worthiness standard discussed above.

(b) Other security acceptable to GTN's lenders.

18.3 (B) Credit-worthiness for Interruptible Transportation Service

(1) GTN shall not be required to perform or to continue interruptible transportation service under this FERC Gas Tariff, Third Revised Volume No. 1-A on behalf of any Shipper who is or has become insolvent or who, at GTN's request, fails within a reasonable period to demonstrate credit-worthiness. Shipper's credit-worthiness shall be determined by providing proof of least two of the items listed below:

(a) A long-term bond or commercial paper rating from Standard and Poors or Moody's equivalent to a "Ba" or better, or a commercial paper rating from Standard and Poors or Moody's equivalent to Prime-3 or better.

(b) Audited financial statements for itself, or for its parent company if it is a subsidiary which is consolidated with its parent company and does not issue stand-alone financial statements, for the two preceding years showing good financial strength.

(c) An estimated financial strength rating by Dun and Bradstreet sufficient to cover the credit to be extended and a corresponding Dun and Bradstreet composite credit appraisal of "fair" or better.

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(Continued)

18. OPERATING PROVISIONS (Continued)

18.3 (B) Credit-worthiness for Interruptible Transportation Service
(Continued)

(d) A demonstration by the Shipper that the Company has sufficient financial capacity or backing to warrant an extension of credit. This demonstration could include proof of banking relationships sufficient to cover the service agreement, or a detailed listing of credit references within the industry, exhibiting a good credit history.

(2) If Shipper does not demonstrate credit-worthiness, Shipper has the option of receiving interruptible transportation service under this FERC Gas Tariff, Third Revised Volume No. 1-A if Shipper provides GTN a letter of credit in an amount equal to the cost of performing the maximum level of service requested for a three (3) month period of time. The letter of credit must be from a credit worthy financial institution and be in place before the Transportation Service Agreement can be signed. The Shipper also has the option of receiving transportation service if Shipper prepays for transportation services on a month-to-month basis pursuant to the following terms:

(a) For a calendar month in which transportation service is desired (delivery month), Shipper must notify GTN no later than eight (8) business days prior to the commencement of delivery month (estimation date) of its estimation of the maximum, cumulative gas deliveries (monthly estimation) desired for the delivery month. (For Shipper's initial monthly estimation, the delivery month, or remaining portion thereof, shall commence eight (8) days after the estimation date.) Notice of monthly estimation may be telephonic or written; telephonic notices must be confirmed in writing and received by GTN within five (5) business days. GTN will advise Shipper within forty-eight (48) hours of the estimation date of the exact dollar amount of the prepayment. Shipper shall not deliver or receive gas in excess of the monthly estimation during delivery month.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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18. OPERATING PROVISIONS (Continued)

18.3 (B) Credit-Worthiness for Interruptible Transportation Service
(Continued)

(b) No later than three (3) business days (settlement date) prior to commencement of delivery month, Shipper shall pay to GTN and GTN shall have received from Shipper lawful money of the United States in an amount equal to the prepayment amount provided to Shipper by GTN described above.

(c) On or before the twentieth (20th) day following

delivery month, GTN shall provide statement to Shipper detailing the transportation service provided during the delivery month. The statement will reconcile the amount prepaid in accordance with the monthly estimation, credit to Shipper, if applicable. Any such credit will be deducted from the prepayment for the following month. Should the Shipper elect not to receive transportation services for the following month, Shipper shall so notify GTN in writing; GTN will issue a check to the Shipper within seven (7) business days following receipt by GTN of such notice.

18.3 (C) Credit-worthiness for Firm and Interruptible Transportation Service

For purposes of this FERC Gas Tariff, Third Revised Volume No. 1-A the insolvency of a Shipper shall be evidenced by the filing by such Shipper or any parent entity thereof (hereinafter collectively referred in this paragraph to as "the Shipper") of a voluntary petition in bankruptcy or the entry of a decree or order by a court having jurisdiction in the premises adjudging the Shipper as bankrupt or insolvent, or approving as properly filed a petition seeking reorganization, arrangement, adjustment or composition of or in respect of the Shipper under the Federal Bankruptcy Act or any Act or any other applicable federal or state law, or appointing a receiver, liquidator, assignee, trustee, sequestrator (or other similar official) of the Shipper

(Continued)

TRANSPORTATION GENERAL TERMS AND CONDITIONS
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18. OPERATING PROVISIONS (Continued)

18.3 (C) Credit-worthiness for Firm and Interruptible Transportation
Service (Continued)

or composition of or in respect of the Shipper under the Federal Bankruptcy Act or any Act or any other applicable federal or state law, or appointing a receiver, liquidator, assignee, trustee, sequestrator (or other similar official) of the Shipper or of any substantial part of its property, or the ordering of the winding-up liquidation of its affairs, with said order or decree continuing unstayed and in effect for a period of sixty (60) consecutive days.

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(Continued)

18. OPERATING PROVISIONS (Continued)

18.4 Upon request of GTN, Shipper shall from time to time submit estimates of daily, monthly and annual quantities of gas to be transported, including peak day requirements.

18.5 GTN shall not be obligated to install additional facilities, other than those specified in Paragraph 4.1 herein, that are required to provide service under this FERC Gas Tariff, Third Revised Volume No. 1-A; provided, however, GTN may install or Shipper may pay all of the expenses incurred for installing additional facilities on a nondiscriminatory basis and under terms that are mutually agreeable. In the event GTN incurs the cost of installing additional facilities on behalf of a Shipper, Shipper shall pay, in addition to the rate(s) stated in the applicable rate schedule, the prorated (based on Transportation Contract Demand) cost of service attributable to any such additional facilities until such time as a different allocation procedure is specified by Commission order.

18.6 Reserved

18.7 Reserved

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Gas Transmission Northwest Corporation

FERC Gas Tariff Sheet Nos. 140 - 141 Third Revised Volume No. 1-A

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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19. PRIORITY OF SERVICE, SCHEDULING, AND NOMINATIONS

19.1 Priority of Firm Service

Firm service shall have the highest priority on GTN's System. From time to time, GTN may not have sufficient capacity to accommodate all nominations for firm service through a given segment of its pipeline, Receipt Point, or Delivery Point. In that event, GTN shall schedule firm service using the following priorities.

19.1A FIRM SCHEDULING PRIORITIES THROUGH PIPELINE SEGMENTS.

GTN shall first schedule nominations for service within a shipper's Primary Path. In the event GTN has insufficient capacity to schedule all nominations for service within Shippers' Primary Paths, GTN shall schedule service to Shippers nominating for service along Primary Paths on a pro rata basis in accordance with each shipper's MDQ.

GTN will next schedule nominations for service within a shipper's Reverse Path. In the event GTN has insufficient capacity to schedule all nominations for service within Shippers' Reverse Paths, GTN shall schedule service to Shippers nominating for service along Reverse Paths on a pro rata basis in accordance with each shipper's MDQ.

19.1B FIRM SCHEDULING PRIORITIES THROUGH RECEIPT POINTS.

First, GTN shall schedule service to those shippers for whom the constrained receipt point is a Primary Receipt Point, up to each shipper's MDQ at that point (plus an allowance for fuel). In the event full service cannot be provided to shippers holding Primary Receipt Point rights, service will be scheduled on a pro rata basis based on each shipper's primary MDQ at that point.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.1B FIRM SCHEDULING PRIORITIES THROUGH RECEIPT POINTS. (Continued)

GTN shall then schedule service to those shippers for whom the constrained receipt point is a Secondary Receipt Point. In the event full service cannot be provided, service will be scheduled on a pro rata basis based on each shipper's MDQ.

19.1C FIRM SCHEDULING PRIORITIES THROUGH DELIVERY POINTS.

GTN shall first schedule service to those shippers for whom the constrained Delivery point is a Primary Delivery Point, up to each shipper's MDQ at that point. In the event full service cannot be provided to shippers holding Primary Delivery Point rights, service will be scheduled on a pro rata basis based on each shipper's MDQ at that point.

GTN shall then schedule service to those shippers for whom the constrained Delivery point is a Secondary Delivery Point. In the event full service cannot be provided, service will be scheduled on a pro rata basis based on each shipper's MDQ.

19.1D SCHEDULING PRIORITY FOR CAPACITY RELEASE

The Scheduling Priorities set out in this Section 19.1 also apply for capacity released under GTN's capacity release program, and are subject to the terms and conditions as specified in an executed firm service agreement between GTN and Shipper. All service under the capacity release program shall be considered firm for purposes of priority of service.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.2 PRIORITY OF INTERRUPTIBLE SERVICE

Interruptible transportation service under this FERC Gas Tariff, Third Revised Volume No. 1-A, shall be provided when and to the extent that capacity is available in GTN's existing facilities, subject to the priorities of service set forth herein. GTN will provide interruptible transportation service first to the Shipper(s) paying the highest rate. (Shippers paying a Negotiated Rate that exceeds the maximum applicable tariff rate shall be considered to be paying the maximum applicable tariff rate.) For the purposes of Section 19.2, the term "highest rate" shall be determined by multiplying the distance in pipeline miles (from the receipt point to the delivery point) by the mileage component(s) of the ITS-1 rate (including applicable surcharges), and then adding the non-mileage component(s) of the ITS-1 rate (including applicable surcharges). In the event of a tie, GTN shall allocate interruptible capacity among interruptible Shippers on a pro-rata basis based on confirmable nominations.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.3 Priority of Authorized Overrun Service

Authorized overrun service shall have a priority lower than firm or interruptible as defined above. Priority within the overrun class shall be determined using a first-come, first-serve procedure.

19.4 Nominations

19.4(a) Information to be Provided with Nomination

A Shipper may nominate for transportation service on GTN electronically in accordance with Section 34 of the General Terms and Conditions of this Tariff. In accordance with NAESB Standard 1.3.5, Version 1.5, all nominations should include Shipper-defined begin dates and end dates. All nominations excluding intraday nominations should have roll-over options. Specifically, Shippers should have the ability to nominate for several days, months, or years, provided the nomination begin and end dates are within the term of Shipper's contract.

All nominations shall include, at a minimum:

a daily quantity of gas to be transported (expressed in Dekatherms);

previously approved and valid receipt and delivery points; and

shipper defined begin dates and end dates.

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(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.4 Nominations (Continued)

19.4(a) Information to be Provided with Nomination (Continued)

Shipper shall provide as a component of its nomination such business conditional data sets as may be required by GTN to enable it to identify, confirm, and schedule the nomination. Shipper shall also prioritize nominated receipts and deliveries when there is more than one supplier and more than one Shipper customer, respectively. Shipper designated priorities will be used to allocate gas when upstream and downstream nominations vary from GTN's Shipper nominations.

Shipper may nominate for any period of days, provided the nomination begin and end dates are within the term of the Shipper's Transportation Service Agreement or exhibit. Such nominations shall be deemed "Standing Nominations." All types of Nominations must be clearly and separately identified so that priorities of service can be distinguished. As required by NAESB Standard 1.3.19, Version 1.5, overrun quantities should be requested on a separate transaction.

The receipt of the nomination is notice that all necessary regulatory approvals have been received and that valid upstream and downstream transportation and other contractual arrangements are in place.

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19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.4 Nominations (Continued)

19.4(b) Nomination Cycles

In accordance with NAESB Standard 1.3.2, Version 1.5, GTN will utilize the following standard nomination cycles:

(i) THE TIMELY NOMINATION CYCLE:

11:30 a.m. (CCT) (9:30 a.m. PCT) nominations leave control of the nominating party;

11:45 a.m. (CCT) (9:45 a.m. PCT) receipt of nominations by GTN (including from Title Transfer Tracking Service Providers (TTTSPs));

12:00 noon (CCT) (2:00 p.m. PCT) GTN sends Quick Response;

3:30 p.m. (CCT) (1:30 p.m. PCT) receipt of completed confirmations by GTN from upstream and downstream connected parties;

4:30 p.m. (CCT) (2:30 p.m. PCT) receipt of scheduled quantities by shipper and point operator (central clock time on the day prior to flow).

(ii) THE EVENING NOMINATION CYCLE:

6:00 p.m. (CCT) (4:00 p.m. PCT) nominations leave control of the nominating party;

6:15 p.m. (CCT) (4:15 p.m. PCT) receipt of nominations by GTN (including from TTTSPs);

6:30 p.m. (CCT) (4:30 p.m. PCT) GTN sends Quick Response;

9:00 p.m. (CCT) (7:00 p.m. PCT) receipt of completed confirmations by GTN from upstream and downstream connected parties;

10:00 p.m. (CCT) (8:00 p.m. PCT) GTN provides scheduled quantities to affected shippers and point operators, and provides scheduled quantities and notice to bumped parties. Advance notice to bumped parties shall be provided by telephone, facsimile, or electronic mail, at the shipper's option.

(Continued)

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.4 Nominations (Continued)

19.4(b) Nomination Cycles (continued)

Scheduled quantities resulting from an Evening Nomination will be effective at 9:00 a.m. (CCT) (7:00 a.m. PCT) on gas day.

(iii) THE INTRADAY 1 NOMINATION CYCLE:

10:00 a.m. (CCT) (8:00 a.m. PCT) nominations leave control of the nominating party;

10:15 a.m. (CCT) (8:15 a.m. PCT) receipt of nominations by GTN (including from TTTSPs);

10:30 a.m. (CCT) (8:30 a.m. PCT) GTN sends Quick Response;

1:00 p.m. (CCT) (11:00 a.m. PCT) receipt of completed confirmations by GTN from upstream and downstream connected parties;

2:00 p.m. (CCT) (12:00 noon PCT) GTN provides scheduled quantities to affected shippers and point operators, and provides scheduled quantities and notice to bumped parties. Advance notice to bumped parties shall be provided by telephone, facsimile, or electronic mail, at the shipper's option.

Scheduled quantities resulting from Intraday 1 Nominations should be effective at 5:00 p.m. (CCT) (3:00 P.M. PCT) on gas day.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.4 Nominations (Continued)

19.4(b) Nomination Cycles

(iv) THE INTRADAY 2 NOMINATION CYCLE:

5:00 p.m. (CCT) (3:00 p.m. PCT) nominations leave control of the nominating party;

5:15 p.m. (CCT) (3:15 p.m. PCT) receipt of nominations by GTN (including from TTTSPs);

5:30 p.m. (CCT) (3:30 p.m. PCT) GTN sends Quick Response;

8:00 p.m. (CCT) (6:00 p.m. PCT) receipt of completed confirmations by GTN from upstream and downstream connected parties;

9:00 p.m. (CCT) (7:00 p.m. PCT) GTN provides scheduled quantities to affected shippers and point operators.

Scheduled quantities resulting from Intraday 2 Nominations should be effective at 9:00 p.m. (CCT) (7:00 p.m. PCT) on gas day.

Firm intraday nominations during the Intraday 2 Nomination Cycle may not bump nominated and scheduled interruptible volumes.

(v) For purposes of GISB Standards 1.3.2 ii, iii, and iv (reflected in Paragraphs 19.4(b)(ii) through 19.4(b)(iv) above), "provide" shall mean, for transmittals pursuant to GISB Standards 1.4.x, receipt at the designated site, and for purposes of other forms of transmittal, it shall mean send or post.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.4 Nominations (Continued)

19.4(b) Scheduling Timelines (Continued)

Transporter shall, at the end of each business day, make available to each Shipper information containing scheduled quantities including scheduled intraday nominations and any other scheduling changes.

GTN shall have the discretion to accept nominations at such later times as operating conditions permit and without detrimental impact to other shippers and upon confirmation that corresponding upstream and downstream arrangements in a manner satisfactory to GTN have been made. In the event later nominations are accepted, GTN will schedule those nominations after the nominations received before the nominations deadline, which is in accordance with NAESB Standard 1.3.6, Version 1.5, that states nominations received after nomination deadline should be scheduled after the nominations received before the nomination deadline.

(Continued)

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.4 Nominations (Continued)

19.4(c) Changes to Nominations

(1) Changes to Standing Nominations

In accordance with NAESB Standard 1.3.7, Version 1.5, all nominations should be considered original nominations and should be replaced to be changed. When a nomination for a date range is received, each day within that range is considered an original nomination. When a subsequent nomination is received for one or more days within that range, the previous nomination is superseded by the subsequent nomination only to the extent of the days specified. The days of the previous nomination outside the range of the subsequent nomination are unaffected. Nominations have a prospective effect only. A nomination for a period within the start and end dates of a Standing Nomination replaces the Standing Nomination for the specific gas day(s) only and does not replace the remainder of the Standing Nomination.

(Continued)

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.4 Nominations (Continued)

19.4(c) Changes to Nominations (Continued)

Such nominations must be received by GTN's Transportation Department in accordance with the scheduling timelines set out in Section 19.4 (b).

In the event GTN does not receive information of upstream or downstream adjustments, GTN shall use the lesser of the new nomination or the previous nomination.

(2) Intraday Nominations

In accordance with NAESB Standard 1.3.8, Version 1.5, all transportation service providers should allow for intraday nominations. Requests to amend previously scheduled nominations may be accepted during the gas day, subject to operational conditions and, further that corresponding upstream and downstream adjustments in a manner satisfactory to GTN can be confirmed. In accordance with NAESB Standard 1.3.11, Version 1.5, such intraday Nominations can be used to request increases or decreases in total flow, changes to receipt points, or changes to delivery points of scheduled gas. A request to increase a nomination for firm transportation up to the MDQ specified in the Service Agreement will be accommodated to the extent operating conditions permit. Firm intraday nominations other than during the Intraday 2 Nomination Cycle shall have priority over nominated and scheduled interruptible volumes. A request to increase a nomination for interruptible transportation shall be permitted only to the extent that capacity is available and that no displacement of other interruptible transportation occurs. Such changes will become effective only when system operating conditions, as determined by GTN, permit changes to occur.

(Continued)

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.4 Nominations (Continued)

19.4(c) Changes to Nominations (Continued)

Intraday Nominations do not have roll-over options and will replace the Standing Nomination only for the duration of the Gas Day. Quantities for Intraday Nominations will be expressed in Dekatherms, and represent the total quantities to be delivered prior to the end of the effective Gas Day.

- (3) In accordance with NAESB Standard 1.3.9, Version 1.5, all nominations, including Intraday Nominations, should be based on a daily quantity; thus, an Intraday Nominator need not submit an hourly nomination. Intraday nominations should include an effective date and time. The interconnected parties should agree on the hourly flows of the Intraday Nomination, if not otherwise addressed in transporter's contract or tariff.

(Continued)

TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.4 Nominations (Continued)

19.4(d) Information Reliability

GTN shall be allowed to rely conclusively on the information submitted as part of the nomination in confirming the nomination for scheduling and allocation. Shipper must provide electronically to GTN Shipper's current designated contact, after hours and emergency telephone numbers. Such information must be updated as often as changes to such information occurs. GTN may rely solely upon the information provided by Shipper and will not be liable to Shipper if Shipper's contact information is outdated and communication attempts with such Shipper are unsuccessful.

19.4(e) Uniform Hourly Rates

Scheduled quantities will be received and delivered at a uniform hourly rate of confirmed quantity divided by 24, unless as determined by GTN, variance from the hourly rate will not be detrimental to the operation of the pipeline or adversely affect other GTN Shippers.

19.4(f) North American Energy Standards Board Standards:

Nominations for service on GTN shall be further governed by the following standards adopted by the North American Energy Standards Board. Unless otherwise specified, all standards are Version No. 1.5:

1.3.13; 1.3.14; 1.3.16; 1.3.22; and 1.3.23.

(Continued)

TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

19. PRIORITY OF SERVICE, SCHEDULING AND NOMINATIONS (Continued)

19.5 Priority of Parking and Authorized Imbalance Service

Parking and Authorized Imbalance Service shall have the lowest priority on GTN's system. All other transportation service, including rectification of imbalances, have superior priority to these services.

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Gas Transmission Northwest Corporation

FERC Gas Tariff Sheet Nos. 157 - 158 Third Revised Volume No. 1-A

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

20. CURTAILMENT

GTN shall have the right to curtail, interrupt, or discontinue Transportation Service on any portion of its system at any time for reasons of Force Majeure or when capacity, supply, or operating conditions so require or it is necessary or desirable to make modifications, repairs, or operating changes to its system. GTN shall provide notice of such occurrences as is reasonable under the circumstances.

Capacity may become constrained at individual receipt points, delivery points or on segments of the pipeline. GTN shall exercise this curtailment provision only at the point(s) or segment(s) of the pipeline affected by the constraint. When capacity is constrained or otherwise insufficient to serve all the transportation requirements which are scheduled to receive service, GTN shall curtail Authorized Imbalance Service; followed by Interruptible Service, and finally Firm service.

Curtailment of Authorized Imbalance Service, if necessary, shall be performed in the opposite order of scheduling as set forth in Section 19.3 of this Tariff.

Curtailment of Interruptible Service, if necessary, will be performed in the opposite order of scheduling set forth in Section 19.2 of this Tariff

Curtailment of firm service if necessary, will be performed pro rata based on the MDQ across the contracts scheduled to use the capacity at the applicable receipt points, delivery point(s) or mainline segment(s) of pipeline.

(Continued)

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

21. BALANCING

Balancing of thermally equivalent quantities of gas received and delivered by GTN shall be achieved as nearly as feasible on a daily basis, with any cumulative imbalance accounted for on a monthly basis. Correction of imbalances shall be the responsibility of the Shipper whether or not notified by GTN at the time of incurrence of the imbalance. Correction of imbalances shall be scheduled with GTN using the nomination process as soon as an imbalance is known to exist based on the best available current data. Nominations to correct imbalances shall have the lowest priority for scheduling purposes and shall be subject to the availability of capacity and other operational constraints for imbalance correction. If on any day capacity is insufficient to schedule all imbalance nominations, all such nominations shall be prorated accordingly. To maintain the operational integrity of its system, GTN shall have the right to balance any Shipper's account as conditions may warrant.

Imbalances shall exist as defined below and be subject to the applicable charges and penalties if not corrected.

a) Actual delivered quantity exceeds MDQ

An imbalance shall exist if the actual delivered quantity on any day exceeds the MDQ and the delivered quantity in excess of the MDQ has not been authorized by GTN (authorized Overrun).

Penalty: A Shipper shall be assessed \$5/Dth for the quantity that is greater than 10% of the MDQ or 1000 Dth, whichever is greater.

In addition, the quantity delivered in excess of the MDQ shall be charged the Authorized Overrun charge as provided in the applicable rate schedule of Shipper.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

21. BALANCING (Continued)

(b) Actual delivered quantity exceeds receipt quantity

A net positive imbalance shall exist if the difference between the delivered quantity and the quantity received, taking into account the reduction in quantity for compressor fuel use, yields a positive result. Commencing upon notification by GTN of the existence of the imbalance, Shipper shall have 3 days to correct the imbalance.

Penalty: If, at the end of the 3 day period the difference between the actual delivered quantity and the receipt quantity is in excess of 10% of the delivered quantity or 1000 Dth, whichever is greater, the Shipper shall be assessed a charge of \$5/Dth applied to the excess quantities. If the imbalance is not corrected within 45 days of GTN's notice of an imbalance, the Shipper shall be assessed an additional charge of \$5/Dth, applied to the net imbalance remaining at the end of the 45 day balancing period.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

21. BALANCING (Continued)

(c) Actual quantity received exceeds delivered quantity

A net negative imbalance shall exist if the difference between the delivered quantity and the quantity received taking into account the reduction in quantity for compressor fuel use, yields a negative result. Commencing upon notification by GTN of the existence of the imbalance, Shipper shall have 3 days to correct the imbalance.

Penalty: If, at the end of the 3 day period the difference between the actual quantity received and the delivered quantity is in excess of 10% of the delivered quantity or 1000 Dth, whichever is greater, the Shipper shall be assessed a penalty of \$2/Dth applied to the excess quantity. If the imbalance is not corrected within 45 days of GTN's notice of an imbalance, GTN shall be able to retain the remaining imbalance quantity without compensation to the Shipper and free and clear of any adverse claim.

(d) Scheduled delivery quantity exceeds actual delivered quantity

An imbalance shall exist when the quantity scheduled (nominated and confirmed) for delivery exceeds the actual delivered quantity.

Penalty: When the difference between the scheduled delivery quantity and actual delivered quantity is in excess of 10% of the actual deliveries, or 1000 Dth, whichever is greater, the Shipper shall be assessed the maximum applicable interruptible transportation rate applied to the excess quantities.

(Continued)

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

21. BALANCING (Continued)

(e) Actual delivered quantity exceeds scheduled delivery quantity

An imbalance shall exist when the quantity delivered exceeds the quantity scheduled (nominated and confirmed).

Penalty: When the difference between the actual delivered quantity and the scheduled delivery quantity is in excess of 10% of the scheduled quantity or 1000 Dth whichever is greater, the Shipper shall be assessed a charge of \$5/Dth applied to the excess quantity.

Imbalance determinations as described above will be performed on a daily basis and each daily occurrence will constitute a separate incident. It is recognized and understood that more than one penalty provision may apply to each imbalance incident.

In the event that any penalty would otherwise be applicable under these provisions as a direct consequence of any action or failure to take action by GTN or the failure of any facility under GTN's control, or an event of force majeure as defined in these Transportation General Terms and Conditions, said penalty shall not apply.

Interruptible Shippers will be notified whether penalties will apply on the day their volumes are reduced. GTN shall waive non-critical penalties for bumped shippers on the day of the bump. Waiver of non-critical penalties shall not relieve the shipper from the obligation to take corrective action to eliminate ongoing imbalances.

The payment of a penalty in dollars pursuant to Paragraph 21 shall under no circumstances be considered as giving any Shipper the right to deliver or take overrun quantities.

Upon termination of a Service Agreement, Shipper shall have 60 days to correct any remaining imbalances. After his period has elapsed, GTN shall have the right to retain any negative imbalance quantity without compensation to the Shipper and shall assess a charge of \$5/Dth for any positive imbalance quantity as applicable.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

21. BALANCING (Continued)

(f) Imbalance Netting: A Shipper may net imbalances between its service agreements, provided that GTN will be reimbursed for any transportation and fuel necessary to effectuate such netting. Resolution of imbalances by netting the Shipper's service agreements shall be scheduled with GTN using the nomination process.

(g) Imbalance Trading:

(1) A Shipper, or its agent, may trade imbalances with other Shippers, their agents or other third-party firms that may conduct imbalance trading for Shippers, provided that GTN will be reimbursed for any transportation and fuel necessary to effectuate such trading. Resolution of imbalances by trading imbalances between Shippers shall be scheduled with GTN using the nomination process.

(2) Any trading of imbalances must result in each Shipper's imbalance decreasing.

(3) GTN shall process all imbalance trades at no additional administrative charge.

(h) Posting Imbalance Trades:

(1) GTN shall provide free of charge an "Imbalance Trading" location on its Internet website to allow posting of imbalances to facilitate trading.

(2) GTN shall post a Shipper's imbalance if the Shipper provides written authorization to GTN authorizing it to post such imbalance information on the "Imbalance Trading" section of its Internet website.

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Gas Transmission Northwest Corporation

FERC Gas Tariff Sheet Nos. 166 - 169 Third Revised Volume No. 1-A

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

22. ANNUAL CHARGE ADJUSTMENT (ACA) PROVISION

22.1 Purpose: GTN shall recover from Shippers the annual charge assessed to GTN by the Federal Energy Regulatory Commission for budgetary expenses pursuant to Section 154.38(d)(6) of the Commission's regulations and Order No. 472 issued May 29, 1987. GTN shall recover this charge by means of an Annual Charge Adjustment (ACA); a per unit rate equivalent to the unit rate assessed against GTN by the Commission shall be included in GTN's transportation rates. (During the period that this ACA provision is in effect, GTN shall not recover in a Natural Gas Act Section 4 rate case annual charges recorded in FERC Account No. 928 assessed to GTN by the Commission pursuant to Order No. 472.)

22.2 Filing Procedure: The notice period and proposed effective date of filings pursuant to this paragraph shall be as permitted under Section 4 of the Natural Gas Act; provided, however, that any such filing shall not become effective unless they become effective without suspension or refund obligation.

22.3 ACA Unit Rate Adjustment: GTN's ACA unit rate shall be the unit rate used by the Commission to determine the annual charge assessment to GTN, and shall be reflected in the Statement of Effective Rates and Charges of this FERC Gas Tariff, Third Revised Volume No. 1-A.

22.4 Affected Rate Schedules: The ACA provision shall apply to all rate schedules contained in GTN's FERC Gas Tariff, Third Revised Volume No. 1-A.

23. SHARED OPERATING PERSONNEL AND FACILITIES

GTN does not share any operating personnel or facilities with its Marketing Affiliates. To the extent PG&E elects service under Rate Schedule USS-1, GTN employees involved with the implementation of USS-1 service will operate independently from GTN's pipeline operating employees.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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24. COMPLAINT PROCEDURES

24.1 Any Shipper or potential Shipper may register a complaint regarding requested or provided transportation service. The complaint may be communicated to GTN primarily by use of GTN's Electronic Bulletin Board (EBB) and secondarily either orally, and/or in writing. Oral complaints should be made to GTN's Manager of Gas Transportation and Services, telephone (503) 833-4300. Written complaints should be sent via registered or certified mail, facsimile (FAX No. (503) 833-4395), or hand delivered to:

Gas Transmission Northwest Corporation 1400 SW Fifth Avenue, Suite 900 Portland, OR 97201
Attention: Manager of Gas Transportation and Services

Oral, written and EBB-submitted complaints must contain the following minimum information:

- Shipper or potential Shipper's name, address, and FAX and telephone numbers;
- Shipper or potential Shipper's contact representative;
- A clear, concise statement of the complaint.

Each complaint will be recorded in GTN's Transportation Service Complaint Log maintained by GTN's Gas Transportation and Services Department located in Portland. Complaints will be logged by date and time received by GTN.

24.2 GTN will initially respond to each complaint within forty- eight (48) hours after GTN receives it. GTN will provide a written response to each complaint within thirty (30) days after GTN receives it. GTN's written response will be sent to Shipper or potential Shipper by certified or registered mail. If the complaint was filed by the EBB, then GTN shall respond via the EBB. A copy of all complaints will be filed in the Transportation Service Complaint Log.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

25. INFORMATION CONCERNING AVAILABILITY AND PRICING OF TRANSPORTATION SERVICE AND CAPACITY AVAILABLE FOR TRANSPORTATION

25.1 Any affiliated or nonaffiliated Shipper or potential Shipper may obtain information concerning the availability and pricing of GTN's transportation services and the pipeline capacity available for transportation by:

(a) Contacting GTN at:

Gas Transmission Northwest Corporation Marketing and Transportation Department 1400 SW Fifth Avenue, Suite 900 Portland, OR 97201
Telephone: (503) 833-4300

Inquiries may be made orally or in writing. Upon request, GTN will provide to any Shipper or potential Shipper a copy of its FERC Gas Tariff, Third Revised Volume No. 1-A, as well as any published notices concerning discounts then available to existing Shippers on the GTN system.

(b) Subscribing to GTN's twenty-four (24) hour Electronic Bulletin Board by calling 1-503-833-4310. The Electronic Bulletin Board provides current information concerning the availability and pricing of transportation service on the GTN system, including all effective rates and discount notices, and capacity available for transportation.

(c) Accessing GTN's Internet Web site through WWW.PGE-NW.COM/OPERATIONS. This web site provides the same information as available on GTN's Electronic Bulletin Board.

25.2 The procedures to be followed by a potential Shipper requesting transportation service from GTN or by an existing Shipper requesting an amendment to its existing service or additional service from GTN are specified in Paragraph 18 of these Transportation General Terms and Conditions.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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**25. INFORMATION CONCERNING AVAILABILITY AND PRICING OF TRANSPORTATION SERVICE AND CAPACITY
AVAILABLE FOR TRANSPORTATION (Continued)**

25.3 The procedures to be followed by Shippers for submitting nominations for transportation service are specified in Paragraph 19 of these Transportation General Terms and Conditions.

26. MARKET CENTERS

The Market Center is defined as a point of interconnection between GTN and other pipelines and local distribution companies. GTN shall provide for Market Centers on GTN. Parties wishing to use Market Centers on the GTN system shall contact GTN for this service. At these Market Centers, entities may trade gas quantities without actively shipping the gas either upstream or downstream of the Market Center. Such entities must nominate for the gas transactions in accordance with the nomination procedures of the Transportation General Terms and Conditions of Third Revised Volume No. 1-A. An entity's nomination for upstream supply and downstream delivery must match the corresponding upstream Shipper nomination and the downstream customer request.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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27. PLANNED GTN CAPACITY CURTAILMENTS AND INTERRUPTIONS

27.1 When GTN needs to temporarily curtail or interrupt service to any Shipper hereunder for the purpose of making planned alterations or repairs, GTN shall give Shipper as much notice as possible of the process so that each Shipper's firm transportation requirements are taken into account in the planning process.

27.2 In the spring of each year GTN shall publish on its Internet Web Site and its electronic bulletin board (EBB) to all Shippers a schedule of planned major maintenance and repairs which affect system capacity. The schedule shall show the estimated delivery point capacity for the next 12 months.

27.3 On a daily basis GTN shall post, on its Internet Web Site and its EBB, capacity for each forthcoming gas day plus the estimated capacity for the next two gas days.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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28. CAPACITY RELEASE

28.1 Eligibility to Release

Any firm Shipper which contracts for firm transportation service under Part 284 of the Commission's regulations (Releasing Shipper) is eligible to release all or part of its capacity (Parcel) for use by another party (Replacement Shipper). Any Replacement Shipper which has previously contracted for a Parcel may also release its capacity to another party as a secondary release subject to the terms and conditions described herein.

Upon releasing a Parcel, consistent with the terms and conditions described herein, all Releasing Shippers shall remain ultimately liable for all reservation charges billable for the originally contracted service. The Releasing Shipper, whether a primary or secondary capacity holder, must post the capacity it seeks to release on GTN's Electronic Bulletin Board (EBB) prior to the close of the Posting Period defined herein.

A Releasing Shipper may release all or a portion of its capacity for the remainder of the term of its contract and extinguish its contractual obligations to GTN with respect to that portion provided that: 1) the Replacement Shipper for this capacity is creditworthy pursuant to GTN's credit standards; and 2) that the rate paid by the Replacement Shipper be no less than the rate contracted between the Releasing Shipper and GTN for the maximum volume, for the remaining term of the contract or the Releasing Shipper's maximum tariff rate. The release may be structured such that the right of first refusal may transfer to the Replacement Shipper even if the release has recall provisions and has been recalled by the Releasing Shipper at the end of the service agreement.

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TRANSPORTATION GENERAL TERMS AND CONDITION
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28. CAPACITY RELEASE (Continued)

28.2 Types of Release

A Releasing Shipper may release a Parcel for a term (Release Term) up to or equivalent to the remaining term under its service agreement with GTN. Types of releases include:

NON-PREARRANGED - BIDDING REQUIRED

(1) Greater than or equal to one day, is not prearranged and requires bidding.

PREARRANGED RELEASES - BIDDING REQUIRED

(1) Greater than thirty-one days at a rate less than the maximum applicable tariff rate. This type of release is prearranged, allows for bidding up to the maximum applicable tariff rate and allows for the right of first refusal. Bidding is pursuant to the methodology selected by the Releasing Shipper.

PREARRANGED RELEASES - BIDDING NOT REQUIRED

(1) Less than or equal to thirty-one days at a rate less than the maximum applicable tariff rate. This type of release is prearranged and does not require bidding. This release cannot be rolled-over, renewed or otherwise extended beyond the term described above unless the Releasing Shipper follows the posting and bidding procedures that apply to the particular term sought contained in this Paragraph 28. The Releasing Shipper may not re-release this Parcel to the same Replacement Shipper until 28 days after the term of the initial release has ended. Rollovers are permitted without bidding or a waiting period provided the Prearranged Shipper agrees to pay the maximum rate and meet all the other terms and conditions of the release.

(2) Greater than or equal to one day at the maximum applicable tariff rate. This type of release is prearranged and does not require bidding.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

28. CAPACITY RELEASE (Continued)

28.3 Notice Requirements

Any Releasing Shipper electing to release capacity shall submit a notice via GTN's EBB that it elects to release firm capacity. The notice shall set forth the following information:

(a) Releasing Shipper's legal name, contract number, and the name, title, address, telephone number, and fax number of the individual responsible for authorizing the release of capacity.

(b) Rate schedule of the Releasing Shipper.

(c) In accordance with NAESB Standard 5.3.26, Version 1.5, Releasing Shipper has choice to specify dollars and cents or percents of maximum tariff rate in the denomination of bids and all transportation service providers should support this. Once the choice is made by the Releasing Shipper, the bids should comport with the choice. In accordance with NAESB Standard 5.3.27, Version 1.5, for purposes of bidding and awarding, maximum/minimum rates specified by the Releasing Shipper should include the tariff reservation rate and all demand surcharges, as a total number or as stated separately. If a volumetric rate is used, Releasing Shipper must indicate whether bids on a reservation charge basis will be accepted as well and if so must specify the method of evaluating the two types of bids. Releasing Shipper also should indicate whether bids will be accepted on a dollar basis or as a percentage of the Releasing Shipper's as-billed rate.

(d) Daily quantity of capacity to be released, expressed in Dth/d, at the designated delivery point(s). (This must not exceed Releasing Shipper's maximum contract demand available for capacity release and shall state the minimum quantity expressed in Dth/d acceptable for release.)

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28. CAPACITY RELEASE (Continued)

28.3 Notice Requirements (Continued)

(e) The term of the release, identifying the date release is to begin and terminate. The minimum release term acceptable to GTN shall be one day.

(f) Whether the Releasing Shipper is willing to consider release for a shorter period of time than that specified in (e) above and if so, the minimum acceptable period of release.

(g) The receipt and delivery point.

(h) Whether Option 1, 2, or 3 shall be used to determine the highest valued bid (see Section 28.7(a) for a description of bid evaluation options 1, 2 and 3).

(i) Whether the Releasing Shipper wants GTN to market its released capacity.

(j) Whether the Releasing Shipper requests to waive the creditworthiness requirements and agrees in such event to remain liable for all charges, or, if the release is for one year (365 days) or less, whether Releasing Shipper requests that the creditworthiness provisions of Paragraph 18.3 (A)(1)(c) shall apply.

(k) Whether Releasing Shipper is a marketing or other affiliate of GTN.

(l) If release is a prearranged release, the Prearranged Shipper must be qualified pursuant to the criteria of Paragraph 28.6(a) unless waived above. Releasing Shipper shall include the Prearranged Shipper bid information pursuant to Paragraph 28.6(b) with its release information and shall indicate whether the Prearranged Shipper is affiliated with GTN or the Releasing Shipper.

(m) Any special nondiscriminatory terms and conditions applicable to the release.

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28. CAPACITY RELEASE (Continued)

28.3 Notice Requirements (Continued)

(n) Tie-breaker method preferred: (1) pro rata, (2) lottery, (3) order of submission (first-come/first-serve). If none are selected, the system defaults to pro rata.

(o) Recall provisions. These provisions must be objectively stated, nondiscriminatory, applicable to all bidders, operationally and administratively feasible as determined by GTN and in accordance with GTN's tariff.

(p) The minimum rate (percentage of: reservation charge or a volumetric equivalent of the maximum reservation charge applicable to the Parcel on a 100% load-factor basis) acceptable to Releasor for this Parcel. Releasing Shipper also should indicate whether bids will be accepted on a dollar basis or as a percentage of the Releasing Shipper's as-billed rate.

(q) Whether the Releasing Shipper is willing to accept contingent bids that extend beyond the close of the Bid Period and, if so, any nondiscriminatory terms and conditions applicable to such contingencies including the date by which such contingency must be satisfied (which date shall not be later than the last day upon which GTN must award capacity) and whether, or for what time period, the next highest bidder(s) will be obligated to acquire the capacity should the winning contingent bidder be unable to satisfy the contingency specified in its bid.

(r) Whether the Releasing Shipper wants to specify a longer bidding period for its Parcel than specified at Paragraph 28.8.

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28. CAPACITY RELEASE (Continued)

28.4 Marketing of Capacity Fee

GTN may act as a facilitator between a Releasing Shipper and a Replacement Shipper(s) that wishes to contract for that Releasing Shipper's capacity. All such Parcels must be posted on the EBB initially. A posting of a Parcel facilitated by GTN will include both the Parcel by the Releasing Shipper and the bid by the Prearranged Shipper. A marketing of capacity fee shall be negotiated between GTN and Releasing Shipper in a nondiscriminatory manner. Such a fee will apply when: a Releasing Shipper requests GTN to market released capacity, GTN actively markets such capacity beyond posting on the EBB, and such marketing results in capacity being released to a Replacement Shipper.

28.5 Posting of a Parcel

The posting of a Parcel constitutes an offer to release the capacity provided a willing Replacement Shipper submits a valid bid consistent with GTN's Transportation General Terms and Conditions. The posting must contain the information contained in Paragraph 28.3. Any specific conditions posted by the Releasing Shipper must be operationally feasible, nondiscriminatory to other shippers, and in conformance with GTN's tariffs. If the Parcel is being released as a secondary release, then any recall provisions included in the primary release which may affect the re-release of this capacity must be included in the terms and conditions of the secondary release. Each Parcel will be reviewed by GTN prior to posting on the EBB for bidding. The receipt of a valid release will be acknowledged by the issuance of a release confirmation to the Releasing Shipper's EBB mailbox by GTN.

It is the Releasing Shipper's sole responsibility to provide release and Prearranged Shipper bid information in advance of the close of the Posting Period.

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28. CAPACITY RELEASE (Continued)

28.5 Posting of a Parcel (Continued)

Releasing Shippers who elect to release capacity based on nondiscriminatory recall provisions and/or special terms and conditions are required to submit their request to release capacity by at least two business days before the close of the Posting Period as stated in Section 28.8. This is to ensure adequate time for GTN to review and validate that any recall and/or special terms and conditions are not discriminatory.

All Prearranged Shipper bids are subject to the Prearranged Shipper(s) meeting the preliminary qualifications as defined in Paragraph 28.6(a) for Replacement Shippers.

A Parcel may be revised or withdrawn by the Releasing Shipper at any time prior to the close of the Posting Period. A Parcel cannot be revised after the close of the Posting Period. In accordance with NAESB Standard 5.3.14, Version 1.5 offers should be binding until written or electronic notice of withdrawal is received by the capacity release service provider. Parcels may be withdrawn subsequent to the close of the Posting Period and up until the close of the Bid Period only in situations where the Releasing Shipper has an unanticipated need for the capacity. In such instances, Releasing Shipper shall notify GTN electronically of its need to withdraw the Parcel due to an unanticipated need for the capacity. The withdrawal or revision of a Parcel will terminate all bids submitted for that Parcel to date. Replacement Shippers will need to resubmit their bids for the Parcel if the Parcel is resubmitted for release.

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28. CAPACITY RELEASE (Continued)

28.6 Bidding for a Parcel

(a) Preliminary Qualification

Replacement Shippers are encouraged to pre-qualify in advance of any postings on GTN's EBB as credit requirements will take differing amounts of time to process depending on the particular financial profile of Replacement Shippers. The pre-qualification process will authorize a pre-set maximum monthly financial exposure level for the Replacement Shipper. Such exposure levels may be adjusted by GTN periodically re-evaluating a Replacement Shipper's credit-worthiness.

Releasing Shippers may exercise their option to waive the credit requirements for any Replacement Shipper wishing to bid on a Parcel posted by that Releasing Shipper. Such waiver must be made on a nondiscriminatory basis. GTN must be informed of such waiver via the EBB before it will authorize such Replacement Shipper's participation with respect to that particular Parcel. In this instance, no pre-set maximum monthly financial exposure level is applicable.

Should a Releasing Shipper waive the credit requirements for a Replacement Shipper, the Releasing Shipper shall be liable for all charges incurred by the Replacement Shipper in the event such Replacement Shipper defaults on payment to GTN for such capacity release service.

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28. CAPACITY RELEASE (Continued)

28.6 Bidding for a Parcel (Continued)

(a) Preliminary Qualification (Continued)

Any potential Replacement Shipper may submit a bid for parcels posted for release. GTN will determine the highest valued bid, based on the bid evaluation method selected by the Releasing Shipper, and verify that the Shipper placing the bid meets GTN's credit requirements before awarding the parcel. Upon notification by GTN of an award of a Parcel, GTN shall complete a new FTS-1 or LFS-1 contract with the particulars of the awarded Parcel and Replacement Shipper shall execute this new contract electronically through the use of an authorization code procedure on the EBB.

Once a Replacement Shipper has acquired capacity, authority is granted to the Replacement Shipper to release that capacity, unless the Releasing Shipper has specified that the Parcel cannot be re-released.

The execution of the FTS-1 or LFS-1 service agreement will constitute an obligation on the part of the Replacement Shipper to be bound by the terms and conditions of GTN's capacity release program as set forth in these Transportation General Terms and Conditions.

(b) Submitting a Bid

All bids must be submitted through the use of GTN's EBB. Such bids shall be "open" for all participants to review. The particulars of all bids will be available for review but not the identity of bidders. GTN will post the identity of the winning bidder(s) only.

A Replacement Shipper cannot request that its bid be "closed", nor can a Releasing Shipper specify that "closed" bids be submitted on its releases. A Replacement Shipper may submit only one bid per Parcel posted at any one point in time. Bids received after the close of the Bid Period shall be invalid. The Replacement Shipper may bid for no more than the quantity of the Parcel posted by the Releasing Shipper. Simultaneous bids for more than one Parcel are permitted.

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28. CAPACITY RELEASE (Continued)

28.6 Bidding for a Parcel (Continued)

(b) Submitting a Bid (Continued)

A valid bid to contract for a Parcel must contain the following information:

- (1) Replacement Shipper's legal name, address, telephone and fax numbers and the name and title of the individual responsible for authorizing the bid.
- (2) The identification of the Parcel bid on.
- (3) Term of service requested. The term of service must not exceed the term included in the Parcel.
- (4) Percentage of the applicable maximum rate, as identified in the Parcel, that Replacement Shipper is willing to pay, or price in dollars and cents per Dth/d, that the Replacement Shipper is willing to pay. A Replacement Shipper may not bid below the minimum applicable charge or rate.
- (5) The quantity desired not to exceed the quantity contained in the Parcel, expressed on a Dth/d delivered basis and greater than the minimum quantity acceptable to Replacement Shipper.
- (6) Whether or not Replacement Shipper is an affiliate of the Releasing Shipper.
- (7) A statement as to whether or not Replacement Shipper is an affiliate of the Releasing Shipper.

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28. CAPACITY RELEASE (Continued)

28.6 Bidding for a Parcel (Continued)

(b) Submitting a Bid (Continued)

(8) An affirmative statement that Replacement Shipper agrees to be bound by the terms and conditions of Rate Schedule FTS-1 and GTN's capacity release provisions in its tariff.

(9) Whether the bid is a contingent bid and the contingencies which must be satisfied by the date specified by the Releasing Shipper in its posting of the Parcel.

(c) Confirmation of Bids

The receipt of a valid bid by GTN will be Shipper's EBB mailbox by GTN. It is the Replacement Shipper's sole responsibility to verify the correctness of the submitted bid and to take any corrective action necessary by resubmitting a bid when notified of an invalid or incomplete bid by GTN via the EBB. This must be done before the close of the Bid Period.

(d) Withdrawn or Revision of Bids

A previously submitted bid may be withdrawn or revised and resubmitted at any time prior to the close of the Bid Period with no obligation on the Replacement Shipper's part. In accordance with NAESB Standard 5.3.15, Version 1.5, bids cannot be withdrawn after the bid period ends. Resubmitted bids must be equal to or greater in value than the initial bids. Lower valued bids will be invalid. In accordance with NAESB Standard 5.3.13, Version 1.5, bids should be binding until written or electronic notice of withdrawal is received by the capacity release service provider.

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28. CAPACITY RELEASE (Continued)

28.7 Allocation of Parcels

(a) Primary Allocation

In accordance with NAESB Standard 5.3.3, Version 1.5, winning bids for Parcels shall be awarded based on one of the following three (3) options to be selected by the Releasing Shipper when posting a Parcel:

Option 1 - Highest Rate Equivalent

Bids will be given priority based on the maximum rate bid as represented by (1) a Replacement Shipper's bid of the percentage of the maximum authorized reservation charge or a volumetric equivalent of the maximum reservation charge applicable to the Parcel on a 100% load factor basis, or (2) a Replacement Shipper's bid in terms of absolute dollars and cents per Dth. A bid queue will be maintained for each individual Parcel.

Option 2 - Present Value

Bids will be given priority based on the net present value of the bid according to the following formula:

$$\text{Present Value per} = P * R * \frac{(1 + i)^{(n)} - 1}{i (1 + i)^{(n)}}$$

where: P = percent of the rate or charge that the Replacement Shipper is willing to pay.

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28. CAPACITY RELEASE (Continued)

28.7 Allocation of Parcels (Continued)

(a) Primary Allocation (Continued)

R = Rate or charge calculated as: The applicable maximum authorized reservation charge(s) per Dth (or a volumetric equivalent of the maximum reservation charge(s) applicable to the Parcel on a 100% load factor basis) in effect at the time of the bid for service from the same receipt point to the same delivery point under the Releasing Shipper's rate schedule.

i = FERC's annual interest rate divided by 12.

n = number of periods for which the bidder wishes to contract, not to exceed the maximum periods to be released by the Releasing Shipper. For releases greater than or equal to one month, the period is the number of months. For releases less than one month the period is the number of days.

A bid queue will be maintained for each individual Parcel.

Option 3 - Net Revenue. Bids will be given priority based on the net revenue for the term of the bid.

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28. CAPACITY RELEASE (Continued)

28.7 Allocation of Parcels (Continued)

(a) Primary Allocation (Continued)

If Releasing Shipper does not specify an option for determining best bid, Option 2 will be the default option used.

Under all options, GTN will evaluate and rank all bids for Parcels.

(b) Right of First Refusal

In the case of a Prearranged Shipper's bid for a Parcel with a term equal to one month or greater, at a rate other than at the highest valued bid, pursuant to the methodology specified by the Releasing Shipper, if the bid submitted by a subsequent Replacement Shipper exceeds the value of the Prearranged Shipper's bid, the Prearranged Shipper will be allowed to match the higher valued bid. The Prearranged Shipper will be allowed a match period, as specified in Section 28.8, to match the higher valued bid, otherwise, the allocation will be awarded to subsequent Replacement Shipper(s) in accordance with the primary and secondary allocation mechanisms.

(c) Secondary Allocation

To the extent there is more than one Replacement Shipper submitting a winning bid, the Parcel shall be allocated based on one of the following tie-breaker methodologies to be selected by the Releasing Shipper: pro rata, lottery, or order of submission (first come/first serve).

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28. CAPACITY RELEASE (Continued)

28.7 Allocation of Parcels (Continued)

(d) Confirmation of Allocation

Upon each completion of an allocation, the successful Replacement Shipper(s) will be notified of the terms under which they have contracted for the awarded Parcel. The notification will be provided in the form of an e-mail to the Replacement Shipper(s). The notice will include the Replacement Shipper's Rate Schedule FTS-1 or LFS-1 service agreement number and the pertinent terms of the Replacement Shipper's bid as well as any additional terms specified by the Releasing Shipper. The Releasing Shipper will be notified of the terms under which its Parcel has been awarded. The notification will be provided in the form of an e-mail to the Releasing Shipper. The notification will include all of the pertinent terms of the Releasing Shipper's parcel.

(e) Purging of Expired Bids

All unfulfilled bids, as well as any unfulfilled portions of bids which receive a partial award, will become ineffective as of the completion of bid reconciliation and the close of the Bid Period. Each unsuccessful Replacement Shipper which has bid shall receive a notice by e-mail indicating the ineffectiveness of the bid.

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28. CAPACITY RELEASE (Continued)

28.7 Allocation of Parcels (Continued)

(e) Purging of Expired Bids (Continued)

Information regarding all bids for all Parcels shall be archived off-line before being purged from the system.

28.8 Scheduling of Parcels, Bids and Notifications

In accordance with NAESB Standard 5.3.2, Version 1.6, the following timelines apply to capacity release transactions.

For biddable releases (less than 1 year):

- offers should be tendered by 12:00 P.M. CCT (10:00 A.M. PCT) on a Business Day;
- open season ends no later than 1:00 P.M. CCT (11:00 A.M. PCT) on a Business Day (evaluation period begins at 1:00 P.M. CCT (11:00 A.M. PCT) during which contingency is eliminated, determination of best bid is made, and ties are broken);
- evaluation period ends and award posting if no match required at 2:00 P.M. CCT (12:00 P.M. PCT);
- match or award is communicated by 2:00 P.M. CCT (12:00 P.M. PCT);
- match response by 2:30 P.M. CCT (12:30 P.M. PCT);
- where match is required, award posting by 3:00 P.M. CCT (1:00 P.M. PCT);
- contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

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28. CAPACITY RELEASE (Continued)

28.8 Scheduling of Parcels, Bids and Notifications (Continued)

For biddable releases (1 year or more):

- offers should be tendered by 12:00 P.M. CCT (10:00 A.M. PCT) four Business Days before award;
- open season ends no later than 1:00 P.M. CCT (11:00 A.M. PCT) on the Business Day before timely nominations are due (open season is three Business Days);
- evaluation period begins at 1:00 P.M. CCT (11:00 A.M. PCT) during which contingency is eliminated, determination of best bid is made, and ties are broken;
- evaluation period ends and award posting if no match required at 2:00 P.M. CCT (12:00 P.M. PCT);
- match or award is communicated by 2:00 P.M. CCT (12:00 P.M. PCT);
- match response by 2:30 P.M. CCT (12:30 P.M. PCT);
- where match required, award posting by 3:00 P.M. CCT (1:00 P.M. PCT);
- contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

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28. CAPACITY RELEASE (Continued)

28.8 Scheduling of Parcels, Bids and Notifications (Continued)

For non-biddable releases:

Timely Cycle

- posting of prearranged deals not subject to bid are due by 10:30 A.M. CCT (12:30 P.M. PCT);
- contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

Evening Cycle

- posting of prearranged deals not subject to bid are due by 5:00 P.M. CCT (3:00 P.M. PCT);
- contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

Intraday 1 Cycle

- posting of prearranged deals not subject to bid are due by 9:00 A.M. CCT (7:00 A.M. PCT);
- contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

Intraday 2 Cycle

- posting of prearranged deals not subject to bid are due by 4:00 P.M. CCT (2:00 P.M. PCT);
- contract issued within one hour of award posting (with a new contract number, when applicable); nomination possible beginning at the next available nomination cycle for the effective date of the contract.

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28. CAPACITY RELEASE (Continued)

28.9 Capacity Recall and Reput

28.9(a) Capacity Recall

Releasing Shipper(s) may, to the extent permitted as a condition of capacity release, recall released capacity (scheduled or unscheduled) at the Timely Nomination cycle and the Evening Nomination cycle, and recall unscheduled released capacity at the Intra-Day 1 and Intra-Day 2 Nomination cycles by providing notice to the Transporter by the following times for each cycle: 8:00 A.M. CCT (6:00 A.M. PCT) for the Timely Nomination cycle; 5:00 P.M. CCT (3:00 P.M. PCT) for the Evening Nomination cycle; 8:00 A.M. (6:00 A.M. PCT) for the Intra-Day 1 Nomination cycle; and 3:00 P.M. (1:00 P.M. PCT) for the Intra-Day 2 Nomination cycle. Notification to replacement shippers shall be provided by Transporter within one hour of receipt of recall notification.

28.9(b) Capacity Reput

In accordance with NAESB Standard 5.3.7, Version 1.5, capacity that has been recalled by the Releasing Shipper may be reput to the Replacement Shipper in accordance with the reput provisions of the release (See Section 28.3(o)). Shipper seeking to reput capacity shall notify GTN of the reput by 8:00 A.M. Central Clock Time (6:00 A.M. PCT). It is the Releasing Shipper's obligation to notify and secure any necessary agreement by the Replacement Shipper to accept the reput under the terms of the release prior to notifying GTN.

28.9(c) In accordance with NAESB Standard 5.3.8, Version 1.5, reput method and rights should be specified at the time of the deal. Reput method and rights are individually negotiated between the Releasing Shipper and Replacement Shipper.

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28. CAPACITY RELEASE (Continued)

28.10 Crediting, Billing Adjustments and Refunds

(a) Eligibility

GTN shall provide revenue credits to any Releasing Shipper which releases capacity to a Replacement Shipper pursuant to the provisions of Paragraph 28. GTN and Shipper may, in connection with a Negotiated Rate Agreement under a firm rate schedule, agree upon payment obligations and crediting mechanisms in the event of a capacity release that vary from, or are in addition to, those set forth in this Section 28.10; provided, however, that terms and conditions of service may not be negotiated.

(b) Monthly Crediting Procedure

Revenue credits for released capacity shall be credited monthly as an offset to a Releasing Shipper's reservation charge (or the volumetric equivalent of the reservation charge on a 100% load-factor basis applicable to the Releasing Shipper. This shall also be referred to in this Paragraph 28.9 as the equivalent volumetric rate) payable to GTN under the applicable rate schedule for the service that has been released. GTN shall credit each month to the Releasing Shipper's account 100% of the revenues from the charges invoiced to the Replacement Shipper(s) for the reservation charge (or equivalent volumetric rate).

(c) Billing Adjustments

GTN shall apply the revenues received from Replacement Shippers first to the reservation charge (or equivalent volumetric rate), next to the GRI reservation surcharge.

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28. CAPACITY RELEASE (Continued)

28.10 Crediting, Billing Adjustments and Refunds (Continued)

(c) Billing Adjustments (Continued)

Should Replacement shipper default on payment to GTN of the reservation charge (or equivalent volumetric rate) GTN shall bill Releasing Shipper for such unpaid charges and apply interest to such adjustments in accordance with the provisions of Paragraph 8 of the Transportation General Terms and Conditions.

(d) Excess Revenue Credits

Releasing Shipper is entitled to excess revenue credits resulting when the reservation charge (or equivalent volumetric rate) revenues actually received by GTN from the Replacement Shipper(s) exceed the reservation charge (or equivalent volumetric rate) revenues which would have been received by GTN from the Releasing Shipper if capacity was not released.

(e) Refunds

GTN shall track all changes in its rates approved by the Commission. In the event the Commission orders refunds of any such rates charged by GTN and previously approved, GTN shall make corresponding refunds to all affected Shippers including Shippers receiving capacity release service

In such instances when rates to Replacement Shippers are reduced, GTN shall make corresponding adjustments to the crediting of revenues to Releasing Shippers for the period such refunds are payable.

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28. CAPACITY RELEASE (Continued)

28.10 Crediting, Billing Adjustments and Refunds (Continued)

(f) In the event Releasing Shipper's Transportation Service Agreement is terminated pursuant to these Transportation General Terms and Conditions, and thirty (30) days notice has been provided to Replacement Shipper(s), a Replacement Shipper that currently holds temporary release capacity has the right to elect to contract with GTN at the Replacement Shipper's MDQ for the remaining term of its release contract and at the lesser of (1) the Releasing Shipper's original contract rate, or (2) the maximum recourse rate, provided that the Replacement Shipper meets GTN's credit-worthiness standards for Firm Transportation Service. The Replacement Shipper shall make its election by the end of the thirty (30) day notice period.

If a Replacement Shipper does not elect to contract with GTN at its replacement MDQ for the remaining term of its release contract and at the rate level that the Releasing Shipper originally contracted for, GTN shall have the right to terminate the Replacement Shipper's Transportation Service Agreement following the election period and offer such capacity through an open season posting that will subject the capacity to competitive bidding. In the event Transporter terminates service, Transporter may exercise all remedies available to it hereunder, at law or in equity.

Replacement Shippers with prospective claims to temporary release capacity will not have rights to such capacity. Prospective claims to permanent releases of capacity will be honored to the extent that a Replacement Shipper meets GTN's credit-worthiness standards for Firm Transportation Service.

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28. CAPACITY RELEASE (Continued)

28.11 Adoption of NAESB Capacity Release Standards

The following NAESB Standards are adopted by, and clarify, the capacity release provisions set forth in this Section 28. Unless otherwise specified, all standards are Version 1.5:

5.3.1, 5.3.4; 5.3.5; 5.3.9; 5.3.11; 5.3.12; 5.3.16; and 5.3.19.

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29. FLEXIBLE RECEIPT AND DELIVERY POINTS

29.1 Firm Service

(a) Addition of a Receipt Point

Any firm Shipper receiving service under Part 284 of the Commission's regulations is entitled to use the receipt point specified in its service agreement as a primary receipt point. A firm Shipper may add a secondary receipt point at any time during the life of the contract provided that secondary receipt point is within the Shipper's Primary Path.

Firm Shippers who are billed under a reservation charge and a delivery rate will continue to be billed reservation charges based on the primary receipt point while delivery rates, including fuel, will be calculated on the receipt point actually used.

To the extent additional meter station capacity or other facilities are required to effect the receipt point change, GTN will construct the additional capacity consistent with Paragraph 18.5.

(b) Changing a Receipt Point

A firm Shipper may change primary receipt points to a different receipt point within its Original Primary Path but will continue to be billed reservation charges based on the original primary receipt point. Changes in receipt points will be permitted provided sufficient receipt point capacity exists at the receiving meter station and subject to any operating constraints. To the extent additional meter station capacity or other facilities are required to effect the receipt point change, GTN will construct the additional capacity at the firm Shipper's expense consistent with Paragraph 18.5.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

29. FLEXIBLE RECEIPT AND DELIVERY POINTS (Continued)

29.1 Firm Service (Continued)

(c) Addition of a Delivery Point

Each firm Shipper is entitled to an allocation of its MDQ to a delivery point(s) as its primary delivery point(s).

A firm Shipper may add secondary delivery points at any time during the life of the contract provided that the secondary delivery points are within the Shipper's Primary Path. In this case, the firm Shipper will continue to be billed any applicable reservation charges based on the primary delivery point; however, delivery rates, including fuel, will be calculated based on the delivery point actually used.

A firm Shipper with primary deliveries allocated to a minor delivery point may add secondary delivery points to its contract provided that the addition of the secondary delivery point does not materially impact service to other firm Shippers.

To the extent additional meter station capacity is required to effect the delivery point(s) change, and subject to any operating constraints GTN will construct the additional capacity consistent with Paragraph 18.5.

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29. FLEXIBLE RECEIPT AND DELIVERY POINTS (Continued)

29.1 Firm Service (Continued)

(d) Changing a Delivery Point

A firm Shipper may change primary delivery points to a different delivery point within its Primary Path but will continue to be billed reservation charges based on the original primary delivery point. A firm shipper may not change its Primary Delivery Point to a location that would change the direction of flow of the Shipper's Primary Path as defined in Section 1.31 of this Gas Tariff. Changes in delivery points will be permitted provided sufficient delivery point capacity exists at the delivery meter station. To the extent additional meter station and subject to any operating constraints capacity is required to effect the delivery point change, GTN will construct the additional capacity at the firm Shipper's expense consistent with Paragraph 18.5.

A firm Shipper with primary deliveries allocated to a minor delivery point may change primary delivery points in its contract provided that the change of primary delivery point does not materially impact service to other firm Shippers.

29.2 Interruptible Service

(a) Change of a Receipt/Delivery Point

Interruptible Shippers will have the right to flexible receipt and delivery points, at a lower priority than firm or released services.

(b) Addition of a Receipt or Delivery Point

Except as otherwise provided in this paragraph, Shippers receiving service under any Part 284 interruptible transportation rate schedule shall be deemed to have access to all receipt and delivery points available under the interruptible transportation rate schedule under which that Shipper is taking service.

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(Continued)

31. NEGOTIATED RATES

31.1 Availability. Notwithstanding anything to the contrary contained in this Tariff, including the provisions of the rate schedules contained herein, GTN and Shipper may mutually agree to a Negotiated Rate under any Agreement, provided that Shipper has not acquired its capacity on a temporary basis under the capacity release provisions of Paragraph 28 of these Transportation General Terms and Conditions. If a portion of the capacity under any existing Agreement is agreed to be priced at Negotiated Rates, the existing maximum or discounted tariff rates will continue to apply to the capacity not subject to the Negotiated Rates. As a recourse to the Negotiated Rates, any Shipper may receive service at applicable maximum tariff rates, including surcharges. The Negotiated Rate may be less than, equal to, or greater than the maximum and minimum applicable tariff rate; may be based on a rate design other than straight-fixed variable; and may include a minimum quantity. GTN's Recourse Rates shall be available to any Shipper that does not agree to a Negotiated Rate. Recourse Rates are set forth on the Rate Sheets within this Tariff.

GTN and a Shipper may agree to a Negotiated Rate for the entire term of a Transportation Service Agreement, or may agree to a Negotiated Rate for some portion of the term of a Transportation Agreement. GTN and Shipper may agree to apply the Negotiated Rate to all or a portion of capacity under Shipper's Firm Transportation Service Agreement.

During the period a Negotiated Rate is in place, the Negotiated Rate shall govern and apply to the Shipper's service under the Negotiated Rate Agreement and the otherwise applicable rate, rate component, charge or credit which the parties have agreed to replace with the Negotiated Rate shall not apply to, or be available to, the Shipper. Only those rates, rate components, charges or credits identified by GTN and Shipper in writing as being superceded by a Negotiated Rate shall be ineffective during the period that the Negotiated Rate is effective; all other rates, rate components, charges, or credits prescribed, required, established or imposed by this Rate Schedule or Tariff shall remain in effect. At the end of the period during which the Negotiated Rate is in effect, the otherwise applicable tariff rates or charges shall govern any service provided to Shipper.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

31. NEGOTIATED RATES (Continued)

31.2 Filing requirement. Unless GTN executes and files a non-conforming agreement, GTN will submit to the Commission on or before the commencement of service under a Negotiated Rate Contract a tariff sheet stating the exact legal name of the Shipper, Negotiated Rate, the rate schedule, the receipt and delivery points, the contract quantities and, where applicable, the Negotiated Rate Formula underlying a Negotiated Rate for any Negotiated Rate Agreement. The filing will contain a provision that the Negotiated Rate Agreement does not deviate any material respect from the Form of Agreement in the tariff for the applicable rate schedule.

31.3 Rate Treatment. GTN shall have the right to seek in future general rate proceedings discount-type adjustments in the design of its rates related to Negotiated Rate Agreements that were converted from pre-existing discount Agreements to Negotiated Rate Agreements. In those situations, GTN may seek a discount-type adjustment based upon the greater of: (a) the Negotiated Rate revenue received; or (b) the discounted tariff rate revenues which otherwise would have been received.

31.4 Limitations. This Paragraph 31 does not authorize GTN to negotiate terms and conditions of service.

31.5 Capacity Release. Negotiated Rates do not apply as the price cap for capacity release transactions. Further, capacity release bids must conform to GTN's applicable tariff rates, as further described in Section 28.6(b)(4) of these Transportation General Terms and Conditions.

31.6 Accounting Treatment. GTN shall maintain separate records for all revenues associated with Negotiated Rate transactions. Transactions related to Negotiated Rate Agreements which originated as a pre-existing discounted service and were subsequently converted will be recorded separately from those originating as Negotiated Rate Agreements. GTN shall record each volume transported, billing determinants, rate component, surcharge, and the revenue associated with its Negotiated Rates so that this information can be filed, separately identified, and separately totaled, as part of and in the format of Statements G, I, and J in GTN's next general rate change application.

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TRANSPORTATION GENERAL TERMS AND CONDITION
(Continued)

32. EQUALITY OF TRANSPORTATION SERVICE

GTN hereby states that the terms and conditions of service for all unbundled sales and transportation services provided in GTN's FERC Gas Tariff, Third Revised Volume No. 1-A, are provided on a basis that is equal in quality for all Shippers. All Shippers can access all sellers of gas and receive the same quality of service on GTN whether their gas supplies are purchased from GTN or any other seller. Furthermore, no preference is accorded to any affiliate of GTN for sales and transportation services provided by GTN.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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33. RIGHT OF FIRST REFUSAL UPON TERMINATION OF FIRM SHIPPER'S SERVICE AGREEMENT

Firm Shippers (original capacity holders) under GTN's firm transportation rate schedules of Third Revised Volume No. 1-A who hold capacity for terms greater than or equal to one year at the maximum authorized reservation charge or rate shall have the right of first refusal at the expiration of their service agreements, subject to the following procedures. Original capacity holders must notify GTN one year prior to the primary expiration date of their service agreements whether they elect to terminate or not to terminate the service agreements.

One year prior to the expiration of the service agreement, GTN will post a notice on its EBB that the original capacity holder's service agreement will expire and whether the original capacity holder has either elected or not elected to terminate.

33.1 In the event original capacity holder elects termination, GTN shall subject this capacity to a bidding process. GTN will commence open bidding no later than 3 months prior to the service agreement expiration. The bid period will be no less than 5 business days in duration. GTN will announce the bid winner(s) as soon as practicable after the close of the bid period, provided, however, that GTN will have no obligation to accept any bid(s) at rates less than the maximum applicable rate in effect. Tied bids will be awarded on a pro rata basis. Winning Shipper(s) and GTN must execute a new firm transportation service agreement prior to service commencement. New long-term Shippers will be subject to the highest incremental fuel rate on the GTN system where such fuel rate otherwise applies to expansion Shippers on the GTN system.

33.2 In the event original capacity holder does not elect termination, GTN will commence open bidding no later than 3 months prior to the service agreement expiration. The bid period will be no less than 5 business days in duration. GTN will notify the original capacity holder of the highest bid(s) as soon as practicable, provided, however, that GTN will have no obligation to accept any bid(s) at rates less than the maximum applicable rate in effect. In the event that GTN does not receive any acceptable bids, the original capacity holder shall not be entitled to continue to receive transportation service upon the expiration of its contract except by agreeing to pay the maximum applicable tariff rate. If GTN accepts any bid(s) the original capacity holder will have 2 weeks from the date of notice

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

**33. RIGHT OF FIRST REFUSAL UPON TERMINATION OF FIRM SHIPPER'S SERVICE
AGREEMENT (Continued)**

33.2 (Continued)

to match the highest bid(s), provided that the original capacity holder shall not have to match any bid rate higher than the maximum applicable rate and shall not be subject to the highest incremental rate on the GTN system. GTN will announce the winning bid(s) as soon as practicable after the close of the match period. If the original capacity holder matches the highest bid(s), the capacity is awarded to the original capacity holder. If the original capacity holder does not match the highest bid(s), the capacity shall be awarded to the highest acceptable bid(s). If there is more than one winning bid, GTN shall award capacity on a pro rata basis. New long-term Shippers will be subject to the highest incremental fuel rate on the GTN system where such fuel rate otherwise applies to expansion shippers on the GTN system. New Shippers must execute a firm transportation service agreement with GTN prior to service commencement. Original capacity holder is allowed to retain a portion of its capacity by matching price and term according to the procedure outlined in this provision, provided that the original contract path is maintained.

33.3 Bids shall be evaluated on the net present value incorporating price and term. The net present value of revenues to be received from a Shipper bidding a Negotiated Rate shall be calculated using the proposed reservation charge revenues and any proposed usage charge revenues guaranteed by a minimum volume commitment or otherwise. Where the Negotiated Rate is based on a Negotiated Rate Formula, the future value of which cannot be determined at the time of the bidding, GTN shall estimate the future revenues to be received under the Negotiated Rate Formula using currently available data.

33.4 If there are no competing bids other than that of the original capacity holder, the rate and terms of continuing service is to be negotiated between existing capacity holder and GTN. In addition, in this instance, if the existing capacity holder agrees to pay the maximum authorized rate, the existing capacity holder may determine the term it desires and GTN must extend its contract to the existing capacity holder accordingly.

33.5 Shippers who terminate their service agreements are not liable for any reservation charges or other charges applicable to the new Shipper contracting for this capacity.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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**33. RIGHT OF FIRST REFUSAL UPON TERMINATION OF FIRM SHIPPER'S SERVICE
AGREEMENT (Continued)**

33.6 Only bona fide bids will be accepted. A bona fide bid offer shall be: (a) submitted via GTN's EBB; (b) accepted in principle; and (c) pursuant to an arms-length transaction. If the Service Agreement is not executed within 30 days, the request for capacity shall expire without prejudice to the prospective Shipper's right to submit a new request for capacity. GTN shall then notify the Shipper via the EBB of the acceptable offer, if any, having the next greatest economic value in accordance with the provisions of this Paragraph. If there is no other acceptable offer, the Shipper may continue service in accordance with this Paragraph.

33.7 Right of first refusal rights held by Shipper continue to apply following an election of termination pursuant to existing evergreen language contained in Shipper's Firm Transportation Service Agreement. A Shipper that holds evergreen rights in addition to a right of first refusal under a Firm Transportation Service Agreement must first elect termination under the evergreen provision in order to initiate the right of first refusal process. When either GTN or Shipper elects termination under an evergreen provision, GTN shall not be obligated to continue Shipper's evergreen rights on a contract extended through the right of first refusal process. Shippers may exercise their right of first refusal rights consistent with this Paragraph 33.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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34. ELECTRONIC COMMUNICATIONS

34.1 Electronic Bulletin Board

GTN shall maintain an Electronic Bulletin Board (EBB) which will provide a range of electronic pipeline services and information to all parties on a nondiscriminatory basis. The EBB is available to any party that has compatible equipment for electronic communication and transmission of data. Access to the EBB is obtained by contacting GTN's EBB Administrator at 503/833-4310 and requesting a user identification. The EBB will operate 24 hours a day; however, certain functions may be limited to specific operating times during the business day. There is no usage fee associated with or charged by GTN for using the EBB.

GTN shall exercise reasonable efforts to ensure the accuracy and security of information presented on the EBB.

34.2 Services Available through the EBB.

GTN's EBB provides information and services to allow shippers to perform a variety of business functions on GTN's system. Information and services include:

(a) Capacity Release

The EBB provides the functionality for all capacity release activities, allowing a Shipper to post capacity for release, review capacity available for release, bid on capacity posted for release, and similar activities. Capacity Release activities include:

- Posting capacity release offers
- Bidding on posted capacity release offers
- Review/download available parcel data
- Review/download historic capacity release data.

(b) Nominations and Confirmations

The EBB provides the functionality for a shipper to create or modify a nomination, receive confirmations, and gain information about the status of the shipper's account.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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34. ELECTRONIC COMMUNICATIONS (Continued)

34.2 Services Available Through the EBB (Con't).

(c) Shipper Account Information

The EBB allows a shipper to obtain a variety of information about its account.

(d) Operations, Information and Bulletins

The EBB provides operational bulletins and maintenance schedules, capacity availability, and credit information.

(e) Want Adds

The EBB provides a forum for Shippers to solicit interest in acquiring or releasing capacity.

(f) Requests For Service

The EBB provides the transportation service request form. This form must be completed in order for a shipper to request new service or receive authorization to bid for capacity posted for release.

(g) Tariff and Rates

The EBB provides GTN's Tariff in searchable form, as well as a summary of GTN's rates for service at major paths.

(h) Available Firm Service

The EBB provides information about GTN's available firm service.

(i) Marketing Affiliate Information

The EBB provides the marketing affiliate information required by the Commission's regulations.

(Continued)

TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

34. ELECTRONIC COMMUNICATIONS (Continued)

34.2 Services Available Through the EBB (Con't)

(j) Complaint Procedures

The EBB outlines procedures for filing complaints.

(k) File Download Area

The EBB allows a shipper to directly download a variety of information, as required by Commission Regulations or as otherwise made available by GTN from time to time.

(l) Help & Contact Information

The EBB provides help and contact information.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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34. ELECTRONIC COMMUNICATIONS (Continued)

34.3 Historical Information

GTN will back up daily transaction information on the EBB. This historical information shall be kept for a three-year period and may be archived off-line. Information that may be accessed includes Parcel information and bid information associated with that Parcel, including the identity of the winning bid and bidder.

GTN will provide access to historical data in one of the following manners:

- (a) Direct access by parties via the EBB. In such cases, data may be viewed, down loaded to a computer or printed by the party.
- (b) GTN may elect to archive historical data off-line. Parties may access this data by sending a written or an electronic mail request to the GTN Capacity Release System Administrator requesting such historical data. GTN will make such information available to Shippers.

34.4 GTN Internet Web Site

GTN maintains an Internet Web Site at WWW.PGE-NW.COM.

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34. ELECTRONIC COMMUNICATIONS (Continued)

34.5 Electronic Data Interface

GTN shall maintain an electronic data interface ("EDI") as required by the standards for electronic delivery mechanisms promulgated by GISB and incorporated in Paragraph 40 of this tariff. EDI is available to any party with access to compatible equipment for electronic communication and transmission of data in accordance with the GISB standards. Access to GTN's EDI system is obtained by contacting GTN's Gas Transportation Department at 503-833-4300.

35. Reserved

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35. Competitive Equalization Surcharge Revenue Credit

(a) Applicability. Competitive Equalization Surcharge ("CES") revenues received by GTN will be credited to Eligible Shippers as set forth below.

(b) Eligible Shippers. A Shipper shall be eligible to receive a credit of CES revenues if it takes service under Rate Schedule FTS-1, LFS-1, or ITS-1.

(c) Timing of Credits. Within 45 days after November 1st of each year, GTN shall determine the total amount of the CES revenues received during the previous 12-month period and the portion of such amount to be credited to each Eligible Shipper as described below. Such revenue credits shall be reflected as a credit billing adjustment on the next bills rendered to the Eligible Shippers. In the event that such credit billing adjustment would result in a net credit on the total bill to any Shipper, or in the event the Eligible Shipper no longer is a shipper on GTN's system, GTN will pay to such Shipper its share of the CES revenues within 15 days after determination of the amount of the credit due to the Shipper.

(d) Allocation Method. CES revenues shall be credited to each Eligible Shipper based on the proportion of the revenues received during the 12-month period from each Eligible Shipper for service rendered under Rate Schedules FTS-1, LFS-1 and ITS-1 (exclusive of service rendered on the Extensions) divided by the total revenue received from Eligible Shippers during such period.

(e) Payment of Interest. GTN shall pay interest to Eligible Shippers on any revenue credits from the date such credits accrue. Such interest shall be calculated based upon the methodology of interest specified in Section 154.501(d) of the Commission's Regulations.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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35A. CREDITING OF INTERRUPTIBLE TRANSPORTATION REVENUES ON EXTENSIONS

(1) Interruptible Transportation Revenue Credits on Coyote Springs Extension

(a) Applicability. Revenue credits from interruptible transportation revenues received by GTN from Rate Schedule ITS-1 (E-3) Shippers shall be provided to GTN's firm Shippers under Rate Schedules FTS-1 (E-3) ("Eligible Shippers"), excluding Shippers receiving service under a Capacity Release Service Agreement.

(b) Crediting Percentage. GTN shall credit to Eligible Shippers 90 percent of interruptible transportation revenues received during each 12-month period, commencing November 1st of each year, but only to the extent that such transportation revenues exceed the amount of fixed costs which were allocated to interruptible transportation (Cost Allocation Amount) by GTN as part of designing GTN's effective transportation rates during such 12-month period. To the extent that GTN is required to provide interruptible transportation revenue credits during any period during which this Paragraph 35A shall be or shall have been in effect for less than 12 months, a "Short Period", GTN shall pro rate the Cost Allocation Amount by the number of days during such Short Period as compared to the total number of days in such 12 months. To calculate the interruptible transportation revenue credit due under the provisions of this paragraph, where applicable, such pro rated Cost Allocation Amount shall be compared to GTN's actual interruptible revenues for the Short Period.

(c) Timing of Credits. Within 45 days after November 1st of each 12-month period or after the end of a Short Period, if applicable, GTN shall determine the total amount of the applicable Rate Schedule ITS-1 (E-3) revenues received during the 12-month period or Short Period and the distribution of the interruptible revenue credits due to Eligible Shippers as described below. Such revenue credits shall be reflected as a credit billing adjustment in the next invoices rendered to the Eligible Shippers. In the event that such credit billing adjustment would result in a credit total invoice to any Shipper, GTN will refund the excess credit billing adjustment to the Shipper in cash within 15 days after determination of the amount of the credit due to the Shipper.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

35A. CREDITING OF INTERRUPTIBLE TRANSPORTATION REVENUES ON EXTENSIONS

(Continued)

(1) Interruptible Transportation Revenue Credits on Coyote Springs Extension (Continued)

(d) Exclusion. Revenue credits shall not be awarded for that portion of interruptible revenues that are attributable to:

(1) the recovery by GTN of variable costs, which portion shall be equal to the minimum usage charge for Rate Schedule ITS-1 (E-3), and (2) relate to other volumetric surcharges such as GRI and ACA.

(e) Distribution Method. Interruptible transportation revenue credits shall be credited to each Eligible Shipper on a pro rata basis in proportion to the reservation revenues received during the 12-month period or Short Period from each Eligible Shipper divided by the total reservation revenue for each Eligible Shipper received during such period. The reservation revenues shall include the reservation charges which the Eligible Shippers actually pay prior to the distribution of all revenue credits, and including reservation charges applicable to capacity which was released into GTN's Capacity Release Programs during the 12-month period year or Short Period by the Eligible Shipper.

(f) GTN shall pay interest to Eligible Shippers on any revenue credits from the date such credits accrue. Such interest shall be calculated based upon the rate of interest specified in Section 154.67(c) of the Commission's regulations.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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35A. CREDITING OF INTERRUPTIBLE TRANSPORTATION REVENUES ON EXTENSIONS

(Continued)

(2) Interruptible Transportation Revenue Credits on Medford Extension

(a) Applicability. Revenue credits from interruptible transportation revenues received by GTN from Rate Schedule ITS-1 (E-1) Shippers shall be credited to the deferred account for Washington Water Power Company's WP Natural Gas subsidiary in accordance with the mechanism approved by Order of June 1, 1995, 71 FERC Paragraph 61,268.

(b) Crediting Percentage. GTN shall credit to the deferred account 90 percent of interruptible transportation revenues received during each 12-month period, commencing November 1st of each year, but only to the extent that such transportation revenues exceed the amount of fixed costs which were allocated to interruptible transportation (Cost Allocation Amount) by GTN as part of designing GTN's effective transportation rates during such 12-month period. To the extent that GTN is required to provide interruptible transportation revenue credits during any period during which this Paragraph 35A shall be or shall have been in effect for less than 12 months, a "Short Period", GTN shall pro rate the Cost Allocation Amount by the number of days during such Short Period as compared to the total number of days in such 12 months. To calculate the interruptible transportation revenue credit due under the provisions of this paragraph, where applicable, such pro rated Cost Allocation Amount shall be compared to GTN's actual interruptible revenues for the Short Period.

(c) Exclusion. Revenue credits shall not be awarded for that portion of interruptible revenues that are attributable to the recovery by GTN of variable costs, which portion shall be equal to the minimum usage charge for Rate Schedule ITS-1 (E-1).

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
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36. DISCOUNT POLICY

36.1 GTN may from time to time offer a discount from the maximum applicable rate for service under any service agreement governed by this FERC Gas Tariff. If and when GTN offers a discount, such discount shall first be applied to the GRI Surcharge and last to the base tariff rate.

36.2 Types Of Discounts

From time to time, GTN and Shipper may agree in writing on a level of discount of the otherwise applicable rates and charges in addition to a basic discount from the maximum rates. For example, GTN may provide a specific discount rate based on:

1) achievement of a specified quantity levels (including quantity levels above, below, or equal to a specified level);

2) specified time periods;

3) specified points of receipt, points of delivery, supply areas, defined geographic areas; or transportation paths; or

4) a specified relationship to the quantities actually transported (i.e., that the rates shall be adjusted in a specified relationship to the quantities actually transported).

In all circumstances the discounted rate shall be between the maximum rate and the minimum rate applicable to the service provided.

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GENERAL TERMS AND CONDITIONS
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37. ADJUSTMENT MECHANISM FOR FUEL, LINE LOSS, AND OTHER UNACCOUNTED FOR GAS PERCENTAGES

The effective fuel and line loss percentages under Rate Schedules FTS-1 and ITS-1 shall be adjusted downward to reflect reductions and may be adjusted upward to reflect increases in fuel usage and line loss in accordance with this Section 37.

37.1 Computation of Effective Fuel and Line Loss Percentage

The effective fuel and line loss percentage shall be the sum of the current fuel and line loss percentage and the fuel and line loss surcharge percentage.

37.2 The Current Fuel and Line Loss Percentage

(a) For each month, the current fuel and line loss percentage shall be determined in accordance with Section 37.2(c) hereof. The current fuel and line loss shall be effective from the first day of such month and shall remain in effect for the month.

(b) The current fuel and line loss percentage to be applicable for the month shall be posted on GTN's Electronic Bulletin Board not less than seven (7) days prior to the beginning of the month.

(c) The current fuel and line loss percentage for the month shall be determined on the basis of (1) the estimated quantities of gas to be received by GTN for the account of Shippers during such month and (2) the projected quantities of gas that shall be required for fuel and line loss during such month, adjusted for overrecoveries or underrecoveries of fuel and line loss during such month preceding the month in which the current fuel and line loss percentage is posted; provided, that the percentage shall not exceed the maximum current fuel and line loss percentage and shall not be less than the minimum current fuel and line loss percentage set forth on the Statement of Effective Rates and Charges.

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GENERAL TERMS AND CONDITIONS
(Continued)

37. ADJUSTMENT MECHANISM FOR FUEL, LINE LOSS AND OTHER UNACCOUNTED FOR GAS PERCENTAGES (Continued)

37.2 The Current Fuel and Line Loss Percentage (Continued)

(d) At least thirty (30) days prior to July 1 and January 1, GTN shall file with the Commission schedules supporting the current fuel and line loss percentages applicable during the six (6) months ending April 30 and October 31, respectively.

37.3 The Fuel and Line Loss Surcharge Percentage

(a) For each six (6) month period beginning July 1 and January 1, the fuel and line loss surcharge percentage shall be determined in accordance with Section 37.3(c) hereof. The fuel and line loss surcharge percentage shall become effective on July 1 and January 1 and shall remain in effect for the six

(6) month period ending December 31 and June 30, respectively.

(b) At least thirty (30) days prior to each July 1 and January 1, GTN shall file with the Commission and post, as defined by Section 154.2(d) of the Commission's regulations, the fuel and line loss surcharge percentage, together with supporting documentation.

(c) The fuel and line loss percentage shall be computed by (i) determining GTN's actual fuel and line loss for the six (6) month period ending April 30, if the effective date is July 1, or October 31, if the effective date is January 1, (ii) subtracting the actual quantities retained by GTN during such six (6) month period, and (iii) dividing the result by the estimated quantities of gas to be delivered by GTN for the account of Shippers during the six month period beginning with the effective date of the fuel and line loss surcharge percentage. If the percentage so determined is 0.0001% or less, the fuel and line loss surcharge percentage shall be deemed to be zero.

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GENERAL TERMS AND CONDITIONS
(Continued)

38. INCREMENTAL FUEL REALLOCATION MECHANISM

When at least one incremental fuel surcharge is currently in effect on the GTN system under this FERC Gas Tariff, new Shippers, taking either long-term firm (LTF) capacity that is available on the GTN system or LTF capacity that is permanently released pursuant to Paragraph 28 of these General Terms and Conditions, will be subject to the highest incremental fuel rate where such fuel rate otherwise applies to expansion Shippers on the GTN system. LTF capacity that is available on the GTN system includes, but is not limited to: capacity that is subject to the right of first refusal process where the existing Shipper has elected to terminate its contract pursuant to Paragraph 33.1 of these General Terms and Conditions; capacity that is subject to the right of first refusal process where the existing Shipper elects not match the highest bid(s) pursuant to Paragraph 33.2; and capacity that has returned to the pipeline because of Shipper default or other contract termination.

The fuel rate that applies to new LTF Shipper(s) will be determined by the following formula, where Incremental Fuel represents the fuel assumption (in Dth) supporting the original incremental fuel rate associated with a particular expansion project and Incremental Dth-miles represents all capacity currently subject to the associated incremental fuel surcharge.

$$\frac{\text{Incremental Fuel (Dth)}}{\text{Incremental Dth-miles} + \text{New LTF Shipper Dth-miles}}$$

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

39. SALES OF EXCESS GAS

GTN may from time to time purchase or sell gas on an interruptible basis at its Stanfield or Kingsgate receipt points as necessary to manage system pressure and maintain system integrity Prior to purchasing or selling gas pursuant to this section, GTN shall post notice of its intent to purchase or sell gas through its EBB. Purchase or sale of gas shall be made on a nondiscriminatory basis.

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TRANSPORTATION GENERAL TERMS AND CONDITIONS
(Continued)

40. Gas Industry Standards

In addition to the NAESB standards incorporated within the text of other provisions of this FERC Gas Tariff, GTN incorporates by reference the following standards. NAESB Standards 1.3.54, 1.3.61, 1.3.63, and 2.3.34 are Version 1.4. NAESB Datasets 1.4.6, 5.4.1, 5.4.2, 5.4.3, 5.4.4, 5.4.7, 5.4.8, 5.4.9, 5.4.13, 5.4.14, 5.4.15, 5.4.18, and 5.4.19 are Version 1.5. Unless otherwise specified, all other standards listed below are Version 1.6:

0.3.1; 1.2.13; 1.2.14; 1.2.15; 1.2.16; 1.2.17; 1.2.18; 1.2.19; 1.3.3; 1.3.4; 1.3.15; 1.3.17; 1.3.18; 1.3.20; 1.3.21; 1.3.24; 1.3.25; 1.3.26; 1.3.27; 1.3.28; 1.3.29; 1.3.30; 1.3.31; 1.3.32; 1.3.33; 1.3.34; 1.3.35; 1.3.36; 1.3.37; 1.3.38; 1.3.39; 1.3.40; 1.3.41; 1.3.42; 1.3.43; 1.3.44; 1.3.45; 1.3.46; 1.3.47; 1.3.48; 1.3.49; 1.3.50; 1.3.51; 1.3.52; 1.3.53; 1.3.54; 1.3.55; 1.3.56; 1.3.57; 1.3.58; 1.3.59; 1.3.60; 1.3.61; 1.3.62; 1.3.63; 1.3.64; 1.3.65; 1.3.66; 1.3.67; 1.3.68; 1.3.69; 1.3.70; 1.3.71; 1.3.72; 1.3.73; 1.3.74; 1.3.75; 1.3.76; 1.3.77; 1.3.78; 1.3.79; 1.4.1; 1.4.2; 1.4.3; 1.4.4; 1.4.5; 1.4.6; 1.4.7; 2.1.5; 2.2.2; 2.2.3; 2.3.1; 2.3.2; 2.3.3; 2.3.4; 2.3.5; 2.3.6; 2.3.8; 2.3.10; 2.3.12; 2.3.13; 2.3.15; 2.3.16; 2.3.17; 2.3.18; 2.3.19; 2.3.20; 2.3.21; 2.3.22; 2.3.23; 2.3.24; 2.3.25; 2.3.26; 2.3.27; 2.3.28; 2.3.31; 2.3.32; 2.3.33; 2.3.34; 2.3.35; 2.3.36; 2.3.37; 2.3.38; 2.3.39; 2.3.40; 2.3.41; 2.3.42; 2.3.43; 2.3.44; 2.3.45; 2.3.46; 2.3.47; 2.3.48; 2.3.49; 2.3.50; 2.4.1; 2.4.3; 2.4.4; 2.4.5; 2.4.6; 2.4.7; 2.4.8; 2.4.9; 2.4.10; 2.4.11; 2.4.12; 2.4.13; 2.4.14; 2.4.15; 2.4.16; 3.3.1; 3.3.2; 3.3.3; 3.3.4; 3.3.5; 3.3.6; 3.3.7; 3.3.8; 3.3.9; 3.3.10; 3.3.11; 3.3.12; 3.3.13; 3.3.16; 3.3.18; 3.3.19; 3.3.20; 3.3.21; 3.3.22; 3.3.23; 3.3.24; 3.3.25; 3.3.26; 3.4.1; 3.4.2; 3.4.4; 4.2.20; 4.3.1; 4.3.2; 4.3.3; 4.3.5; 4.3.6; 4.3.7; 4.3.8; 4.3.9; 4.3.10; 4.3.11; 4.3.12; 4.3.13; 4.3.14; 4.3.15; 4.3.16; 4.3.17; 4.3.18; 4.3.19; 4.3.20; 4.3.21; 4.3.22; 4.3.23; 4.3.24; 4.3.25; 4.3.26; 4.3.27; 4.3.28; 4.3.29; 4.3.30; 4.3.31; 4.3.32; 4.3.33; 4.3.34; 4.3.35; 4.3.36; 4.3.37; 4.3.38; 4.3.39; 4.3.40; 4.3.41; 4.3.42; 4.3.43; 4.3.44; 4.3.45; 4.3.46; 4.3.47; 4.3.48; 4.3.49; 4.3.50; 4.3.51; 4.3.52; 4.3.53; 4.3.54; 4.3.55; 4.3.56; 4.3.57; 4.3.58; 4.3.59; 4.3.60; 4.3.61; 4.3.62; 4.3.63; 4.3.64; 4.3.65; 4.3.66; 4.3.67; 4.3.68; 4.3.69; 4.3.70; 4.3.71; 4.3.72; 4.3.73; 4.3.74; 4.3.75; 4.3.76; 4.3.78; 4.3.79; 4.3.80; 4.3.81; 4.3.82; 4.3.83; 4.3.84; 4.3.85; 4.3.86; 4.3.87; 4.3.88; 5.3.10; 5.3.17; 5.3.18; 5.3.20; 5.3.21; 5.3.22; 5.3.23; 5.3.24; 5.3.25; 5.3.28; 5.3.29; 5.3.30; 5.3.31; 5.3.32; 5.3.33; 5.3.34; 5.3.35; 5.3.36; 5.3.37; 5.3.38; 5.3.39; 5.3.40; 5.3.41; 5.3.42; 5.3.43; 5.3.44; 5.3.45; 5.3.46; 5.3.47; 5.3.48; 5.3.49; 5.3.50; 5.3.51; 5.3.52; 5.3.53; 5.3.54; 5.3.55; 5.3.56; 5.3.57; 5.3.58; 5.4.1; 5.4.2; 5.4.3; 5.4.4; 5.4.5; 5.4.6; 5.4.7; 5.4.8; 5.4.9; 5.4.10; 5.4.12; 5.4.13; 5.4.14; 5.4.15; 5.4.16; 5.4.17; 5.4.18 and 5.4.19.

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EXHIBIT 10.5

OPERATING AGREEMENT

BETWEEN

PACIFIC GAS AND ELECTRIC COMPANY

AND

PACIFIC GAS TRANSMISSION COMPANY

DATED

July 9, 1996

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PG&E/PGT OPERATING AGREEMENT

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OPERATING AGREEMENT

THIS OPERATING AGREEMENT (Agreement) is made and entered into this 9th day of July, 1996, by and between PACIFIC GAS TRANSMISSION COMPANY (PGT), a California corporation, and PACIFIC GAS AND ELECTRIC COMPANY (PG&E), a California corporation. PGT and PG&E shall also be hereinafter referred to individually as a "Party" and jointly as the "Parties."

RECITALS

WHEREAS, PGT owns and operates an interstate natural Gas pipeline transmission system which extends from a point of interconnection with the pipeline facilities of Alberta Natural Gas Company Ltd. (ANG) at the International Boundary near Kingsgate, British Columbia, through the states of Idaho, Washington, and Oregon to a point of interconnection with PG&E's pipeline system at the Oregon-California border near Malin, Oregon. PGT is regulated by and operates subject to the rules and regulations of the Federal Energy Regulatory Commission (FERC) and transports Gas to points along its pipeline system; and

WHEREAS, PG&E is a "local distribution company served by an interstate pipeline" within the meaning of Sections 2(17) and 311 of the Natural Gas Policy Act of 1978 and the Regulations of the FERC thereunder and is a "gas utility" as defined in the Public Utilities Code of the State of California and subject to the jurisdiction of the California Public Utilities Commission (CPUC) and

WHEREAS, PG&E and PGT desire to enter into this Agreement to provide for the terms and conditions under which Gas will be delivered by PGT and accepted by PG&E, or delivered by PG&E and accepted by PGT, for the account of Shipper(s) and/or their designees at the Interconnect Point.

NOW, THEREFORE, in consideration of the premises and mutual benefits and covenants herein contained, PG&E and PGT hereby agree as follows:

1. DEFINITIONS

Except in those instances where this Agreement expressly states another meaning, the following capitalized terms, when used in this Agreement, shall have the following meanings.

1.0 Average Daily Delivery Pressure - The average delivery pressure on any Day.

1.1 Backhaul Service - The contractual delivery of Gas at the Interconnect Point in the direction opposite to the physical movement of the Gas.

1.2 British Thermal Unit or Btu - The amount of energy required to raise the temperature of one (1) pound of pure water one degree Fahrenheit (1 degrees F) from fifty-nine degrees Fahrenheit (59 degrees F) to sixty degrees Fahrenheit (60 degrees F) at a standard pressure of 14.73 psia.

1.3 CPUC - The California Public Utilities Commission or any successor regulatory body.

1.4 Cubic Foot/Feet (Standard Cubic Foot/Feet) - The volume of Gas which occupies one (1) cubic foot when such Gas is at a temperature of sixty degrees Fahrenheit (60 degrees F) and at a pressure of 14.73 psia.

1.5 Day and Daily - For Gas control purposes, a period of twenty-four (24) consecutive hours beginning at 7:00 a.m. Pacific Standard Time (PST) on any calendar day and ending at 7:00 a.m. (PST) on the calendar day immediately following.

1.6 FERC - The Federal Energy Regulatory Commission or any successor regulatory body.

1.7 Heating Value - The amount of heat, measured in Btu's, produced by the complete combustion of a dry Cubic Foot of Gas. The Heating Value shall be the gross or higher amount of heat which is obtained when all of the products of combustion are cooled to 60 degrees F.

1.8 Interconnect Point - The point at which the PGT and PG&E Facilities interconnect in Section 24, T41S, R12E, WM in Klamath County, Oregon, at the California/Oregon border, more commonly known as Malin, Oregon.

1.9 Mcf - One thousand (1,000) Cubic Feet.

1.10 MMBtu - One million (1,000,000) Btu (or Decatherm).

1.11 Natural Gas and Gas - Shall mean any mixture of hydrocarbons or of hydrocarbons and non-combustible gases, in a gaseous state, consisting essentially of methane. Such Gas is typically produced in its natural state from wells, including casinghead and residue gas.

1.12 Normal Operating Conditions - Shall mean that no force majeure conditions (as defined in Paragraph 12.2 herein) exist and that the compressors, pipelines and appurtenant facilities on the respective Parties' pipeline system operate in such a manner to permit such pipeline to meet its firm Shippers' Daily Scheduled Volumes up to such Shippers' maximum Daily contract quantities.

1.13 PG&E Facilities - The piping, land rights, valving, flow control, data acquisition and other appurtenant equipment installed, owned and operated by PG&E at and downstream of the Interconnect Point.

1.14 PGT Facilities - The piping, land rights, measurement, odorizing equipment, valving, flow control, data acquisition and other appurtenant equipment installed, owned and operated by PGT.

1.15 Scheduled Volumes - The quantity of Gas for each Shipper of Gas on PGT that is scheduled by PGT for delivery to PG&E, and in the case of backhaul service, scheduled by PG&E for delivery to PGT.

1.16 Shipper(s) - A third party for whose account Gas is delivered on a firm or interruptible basis at the Interconnect Point from PGT to PG&E or from PG&E to PGT in the case of Backhaul Service.

2. DELIVERY OF GAS

2.1 The Parties hereto mutually agree to permit deliveries of Gas by physical delivery by PGT to PG&E, and in the case of Backhaul Service, deliveries by PG&E to PGT.

2.2 Each Party shall attempt to schedule maintenance of its respective facilities, to the extent operationally feasible, to minimize any interruption of nominated volumes on the other Party's pipeline.

2.3 Unless excused by force majeure (as defined in Paragraph 12.2 hereof), PGT shall deliver Gas to PG&E at the Interconnect Point at a pressure sufficient to effect delivery into PG&E's pipeline against the pressure prevailing therein from time to time as mutually agreed to by the Parties up to a maximum of 911 pounds per square inch gauge (psig) (Maximum Pressure) and not below a minimum of 700 psig (Minimum Pressure). The Parties may agree on other Maximum and Minimum Pressures from time to time to ensure efficient operation of each Party's system at the Interconnect Point.

2.4 Under Normal Operating Conditions, PGT will maintain an Average Daily Delivery Pressure at the Interconnect Point of no less than 855 psig or as otherwise agreed to by the Parties. Under Normal Operating Conditions, PG&E will operate its system so that PG&E will be able to receive one hundred percent (100%) of the Scheduled Volumes from PGT at the Interconnect Point at the Average Daily Delivery Pressure. The Parties agree to cooperate in the day-to-day operation of both systems to ensure efficient and coordinated operation(s) and maintenance.

2.5 The Parties acknowledge the historical coordinated nature of the design of their respective pipeline systems. The Parties also acknowledge the changing nature of their respective Shippers' contractual obligations. Accordingly, the Parties agree not to modify the facilities or operations, other than for reasonable or necessary maintenance, on their respective systems during the term of this Agreement in any manner that will permanently prevent the delivery of Gas pursuant to any existing contractual obligations to their respective firm Shippers, as exercised by such shippers, with a Malin primary receipt or primary delivery point under Normal Operating Conditions.

3. GAS BALANCING

3.1 The Parties have entered or may enter into one or more agreements with Shippers for the transportation of Gas to or from the Interconnect Point on their respective systems. The Parties will transport such Gas for each Shipper's account to or from the Interconnect Point subject to the respective Party's receipt of a Scheduled Volume from the Shipper or its agent. The quantity of Gas confirmed and scheduled to flow between the Parties each Day may be greater or less than the quantity actually delivered at the Interconnect Point, resulting in over- or under-deliveries relative to the gas confirmed and scheduled to flow. The Parties agree to implement the following balancing arrangement, which will facilitate more efficient operations, accounting, and systems management at the Interconnect Point and on the Parties' respective systems and to provide each Party's operating personnel flexibility to operate and control Daily variations in nominated and allocated volumes:

- a. All imbalances shall be recorded on an MMBtu basis.
- b. For Gas accounting purposes, all Daily Scheduled Volumes as scheduled on the flow day shall be deemed to be delivered from each Party's pipeline system into the other Party's pipeline system, regardless of the actual volume of Gas delivered.

- c. When the net volume of Scheduled Volumes on a Day are greater than the actual volume of Gas delivered on such Day, the difference shall be identified on the delivering Party's monthly statements as underdelivered or a negative imbalance account volume.
- d. When the net volume of Scheduled Volumes on a Day are less than the actual volume of Gas delivered on such Day, the difference shall be identified on the delivering Party's monthly statements as overdelivered or a positive imbalance account volume.
- e. PGT and PG&E shall cooperate in order to minimize the Daily over and under deliveries. In this regard, PGT's gas control and transportation personnel and PG&E's gas control and scheduling personnel shall be in contact each day, as needed, to establish the rate at which Gas shall be delivered until the end of the Day in order to balance daily delivered volumes of Gas with Scheduled Volumes of Gas.
- f. PGT shall provide PG&E, no later than the 12th day of each month, a statement showing the total volume of Gas delivered to PG&E at the Interconnect Point during the previous month. PG&E shall verify such statement by the 28th day of the same month. Neither the deliverance or such statement nor the subsequent verification of such statement shall constitute a waiver of either party's rights under Section 6.4.
- g. Further, no later than the 12th day of each month, PGT shall calculate the Daily underdelivered and/or overdelivered positions for each Day in the prior month to determine the overall imbalance for the month (Monthly Imbalance). PGT shall then provide PG&E with the Monthly Imbalance so determined, together with sufficient documentation to enable PG&E to verify the accuracy of the Monthly Imbalance calculation. PG&E shall verify such statement by the 28th day of each month. Neither the deliverance of such statement nor the subsequent verification

of such statement shall constitute a waiver of either party's rights under Section 6.4.

h. The Parties shall mutually agree on which Days the Monthly Imbalance shall be adjusted, taking into consideration current operation of each pipeline system. The Parties shall use their best efforts to adjust any imbalance toward zero as soon as practical but in no case later than thirty (30) Days after the end of each calendar month in which the Parties determined the imbalance existed, unless agreed to otherwise by the Parties.

i. PGT shall provide PG&E a Daily report of the Scheduled Volumes of Gas, within two (2) hours after the end of each Day. The Scheduled Volumes of Gas reported by PGT will be used in the Monthly Imbalance calculation. Any revisions to this data must be mutually agreed to by PG&E and PGT.

j. For the purpose of this Agreement, delivery of any Gas to resolve a Monthly Imbalance is not subject to sales or transportation charges by either Party.

k. Volumes delivered shall be nominated on a Daily basis but will flow on an hourly basis. If curtailment of deliveries during the Day is necessary, Scheduled Volumes shall be adjusted according to the methodology prescribed in the constrained pipeline's tariffs. In this situation, the adjusted Scheduled Volume shall be deemed to have flowed to the receiving Party in accordance with the procedures in paragraph 3.1.

3.2 Risk of loss of all Gas shall pass at the Interconnect Point. PG&E shall not be responsible to Shipper or third parties for any Gas losses or delays (due to operating conditions or constraints, force majeure or otherwise) or damages occurring on PGT's side of the Interconnect Point, and PGT shall not be responsible to Shippers or third parties for Gas losses or delays (due to operating conditions or constraints, force majeure or otherwise) or damages occurring on PG&E's side of the Interconnect Point.

3.3 Either Party may pursue resolution of a dispute as to imbalances owed hereunder in accordance with Section 13 herein, however, unless the Parties mutually agree otherwise, delivery of the entire imbalance due as identified in subparagraph 3.1.g., including any disputed imbalance, shall be made to the respective Party notwithstanding such dispute resolution. Delivery of the disputed imbalance(s) shall not be deemed to be a waiver of any rights to recoup any imbalance amount in dispute.

4. TERM

This Agreement shall have an initial term commencing on the date of execution of this Agreement and ending December 31, 2001. The Agreement shall extend year-to-year thereafter unless terminated as of the end of the initial term or at any time thereafter upon a minimum of one hundred and eighty (180) calendar days prior written notice by either Party to the other.

5. GAS QUALITY

5.1 PGT agrees that the Gas delivered by PGT to PG&E at the Interconnect Point shall meet or exceed PGT's Gas quality specifications as listed in Paragraph 3 of the General Terms and Conditions of PGT's FERC Gas Tariff, First Revised Volume 1-A as amended from time to time.

5.2 Notwithstanding the quality specifications set forth in either PG&E's Rule 21 or PGT's FERC gas tariff, the Gas delivered hereunder shall have a minimum total heat value of Nine Hundred Ninety-Five (995) (Minimum Heat Value) Btu's per Cubic Foot on a dry basis and a maximum total heat value of One Thousand Eighty (1080) (Maximum Heat Value) Btu's per Cubic Foot on a dry basis. If neither Party's system is jeopardized, the Parties may agree on other Maximum and Minimum Heat Values from time to time.

5.3 PGT shall annually, and at any time upon request by PG&E, test the Gas that is delivered to PG&E to determine whether there are any Polychlorinated biphenyls (PCBs) in the Gas or liquids associated with or condensing from the Gas and provide such test results to PG&E. PGT shall provide at its cost the annual test for PCBs. Payment for additional tests

requested by PG&E shall be in accordance with Paragraph 6.2 herein. The Parties shall agree upon a sample point and procedures to be utilized in obtaining the samples and sample results. Sample tests to determine the PCB concentration shall be made in accordance with EPA Method 8080, as published in Test Methods for Evaluating Solid Waste, 3rd ed., Environmental Protection Agency, 1992 (EPA SWA-846), or other mutually agreeable method. Should the test results indicate the presence of PCBs in the Gas or liquids associated with or condensing from the Gas, the Parties agree that a technical advisory committee consisting of representatives from each Party shall meet within 72 hours of the receipt of the test results to establish mutually acceptable procedures to address the discovery of any PCBs in any Gas delivered to PG&E on PGT's system.

5.4 The Parties recognize that the Gas quality specifications in effect for the pipeline systems of each Party are critical to each Party's system integrity and public safety. Accordingly, the Parties agree that remedies may be necessary and appropriate to maintain the safety and reliability of each Party's system. Therefore, if, at any time, the Gas offered for delivery by PGT should fail to conform to any of the quality specifications set forth in either PG&E's Rule 21, PGT's gas FERC tariff, or the specifications set forth in subparagraph 5.3 and should such deficiency jeopardize the public safety, reliability, or merchantability of the Gas, PG&E will provide evidence of such jeopardy to PGT for PGT's immediate consideration. Upon PGT's mutual agreement that such jeopardy exists, which cannot be unreasonably withheld, the Parties will move directly into discussions to determine a mutually acceptable remedy which may include a temporary restriction in delivery of such Gas at the Interconnect Point until such jeopardy is eliminated. Both Parties agree to use commercially best efforts and actions to correct such jeopardy in a timely manner. Notwithstanding any of the above, PG&E shall at all times retain the right to take any such action necessary to protect the integrity of its Gas pipeline system.

5.5 All Gas delivered to PG&E at the Interconnect Point shall be odorized by PGT with a commercially available odorant blend as specified by PG&E with a concentration to be specified by PG&E. Unless the Parties agree to a different concentration, the odorant concentration level will be no more than one half (0.5) grain of odorant per one hundred (100)

standard Cubic Feet. The Parties recognize that such odorant service is provided for the benefit of PG&E. Furthermore, the Parties recognize that the cost recovery of odorization is currently imbedded in the rates set out in PGT's FERC approved tariff and is subject to change in future rate cases. As such, future cost allocation may change over time as approved by FERC.

6. MEASUREMENT AND TESTS

6.1 PGT shall perform the actual measurements each month during the term hereof in accordance with the provisions set forth in Paragraphs 4 and 5 of the General Terms and Conditions of PGT's FERC Gas Tariff, First Revised Volume 1-A as may be revised from time to time. For the purposes of this Agreement, PGT shall perform such measurement and tests as follows:

a. The volume of Gas delivered under this Agreement shall be measured by orifice meters, or by other industry accepted meters installed, maintained and operated by PGT or its designee as mutually agreed to by the Parties.

b. The unit of volume for purposes of measurement shall be one
(1) Cubic Foot of Gas at a temperature base of sixty degrees Fahrenheit (60 degrees F) and at a pressure base of fourteen and seventy-three hundredths (14.73) pounds per square inch absolute (psia).

c. Relative density, carbon dioxide, nitrogen and Heating Value, shall be continuously measured and recorded using Gas chromatographs, calorimeters, densitometers, or other means acceptable in the Gas industry or as mutually agreed to by the Parties. Determination of Heating Value and relative density by compositional analysis shall comply with the methods specified in the American Society for Testing and Materials, ASTM D 3588, as may be revised from time to time. The physical properties of the constituent Gases used to calculate Heating Value and relative density shall be taken from the Gas Processors Association Bulletin GPA 2145, as may be revised from time to time.

d. Gas compressibility shall be calculated at the flowing pressure and temperature under which Gas is delivered to PG&E in accordance with the recommendations contained in the American Society for Testing and Materials, ASTM 3588, as may be revised from time to time.

e. The average atmospheric (barometric) pressure shall be assumed to be 12.67 psia at measurement point. Corrections for other elevations shall be determined by using an industry acceptable equation or by making measurements at the applicable point.

6.2 Routine tests for gas quality will be conducted in accordance with Paragraph 3.2c of the General Terms and Conditions of PGT's FERC Gas Tariff, First Revised Volume No. 1-A as may be revised from time to time. Additional tests for total sulfur, PCBs, and hydrogen sulfide content of the Gas delivered hereunder shall be performed at the request of either Party from time to time but shall be limited to no more than one (1) request every thirty (30) Days. The methods of testing shall be agreed upon by the Parties. PGT shall perform routine tests for gas quality at its expense. Any additional tests for gas quality requested by PG&E shall be performed at PG&E's expense.

6.3 PG&E may witness all tests made hereunder, provided, however that PG&E may not alter or in any manner operate, disturb, manipulate, or tamper with any PGT's equipment or the equipment of a third party vendor. Upon request, PGT shall test its measurement equipment to verify the accuracy of such equipment. PG&E may request a test at any time but shall be limited to no more than one (1) request every thirty (30) Days. At the time of such a request, PGT will schedule with PG&E a mutually convenient time for the test to take place but no later than fifteen (15) Days following the request. Payment for such accuracy tests shall be made in accordance with Paragraph 4 of the General Terms and Conditions of PGT's FERC Gas Tariff, First Revised Volume No. 1-A as may be revised from time to time.

6.4 Notwithstanding Paragraph 4.3 of PGT's FERC Gas Tariff, the following action will be taken for volume correction or determination, if measurement inaccuracy (Inaccuracy) is discovered:

a. When the Inaccuracy is a result of using incorrect constant values in the orifice meter equation, the quantity of delivered Gas shall be recalculated. If the duration of the Inaccuracy cannot be determined or agreed upon, the period of the Inaccuracy shall be deemed to be one half of the time elapsed since the last meter and instrument inspection. Examples of using incorrect constant values include, but are not limited to, basing calculations on the incorrect orifice plate size, orifice tube size, differential pressure range, static pressure range, Heating Value constants of Gas constituents, or relative density constants of Gas constituents.

b. When the Inaccuracy is a result of errors in the calibration or operation of flow computers, transducers, recorders, or measuring devices for relative density or Heating Value, that result in an error greater than one percent (1%) of the measured volume at a reading corresponding to the average reading for the period since the preceding test of the device or devices found to be in error, the quantity of Gas which has been delivered shall be recalculated. If the percentage of error is not ascertainable by calibration, test, or mathematical calculation, the correction shall be made by estimating the quantity or quality of Gas delivered based upon deliveries under similar conditions during a period when the equipment was registering accurately. Where the duration of the Inaccuracy is not known or agreed upon, the period of the Inaccuracy shall be deemed to be one-half of the time elapsed since the date of the last test.

c. Adjustments for Inaccuracies in accordance with 6.4a and 6.4b shall be made provided that the chain therefor shall have been made within twelve (12) months from the date of the disclosure of the error.

7. REGULATORY

7.1 This Agreement is subject to all valid applicable local, state and federal laws, orders, rules, and regulations of any governmental body, agency, or official having jurisdiction.

7.2 PG&E shall not be required to take any action hereunder, including but not limited to entering into any contracts with Shippers or other parties transporting Gas on PGT's Facilities to the Interconnect Point, which, in the good-faith and reasonable exercise of PG&E's judgment, may jeopardize PG&E's retention of its "Hinshaw Exemption."

7.3 PGT shall not be required to take any action hereunder, including, but not limited to, entering into contracts with Shippers or other parties transporting Gas on PG&E's facilities, which, in the good-faith and reasonable exercise of PGT's judgment, may cause PGT to be subject to the jurisdiction of the CPUC.

7.4 Notwithstanding the other provisions of this Agreement, if at any time during the term hereof, any governmental authority having jurisdiction shall take any action whereby either Party's delivery, receipt, and/or use of Gas hereunder shall be proscribed or subjected to terms, conditions, regulations, restraints, or limits that in the reasonable judgment of the Party prevents that party from acting in a commercially reasonable manner to fulfill the terms of this Agreement, such Party shall have the unilateral right to terminate this Agreement at any time upon thirty (30) days written notice to the other Party, without further liability hereunder, except as to redelivery of any outstanding Gas imbalances. Nothing herein shall prevent the Parties through mutual agreement from modifying this Agreement in lieu of termination.

7.5 Nothing in this Agreement shall be interpreted to require either Party to take any action that would be inconsistent with their applicable tariffs or violate any governmental regulation or authority.

7.6 Nothing herein shall be construed as a dedication by either party of its respective facilities to the other Party. Both PG&E and PGT may each construct facilities on its respective system as it may deem necessary or appropriate in its sole discretion. Nothing herein obligates

either Party to construct any additional facilities (including measuring facilities) or to modify any existing facilities to provide for the receipt or delivery of Gas. PGT shall have a separate agreement(s) covering any new facilities or necessary modifications for either receipt or delivery of Gas at the Interconnect Point.

8. REMEDIES

Each Party agrees that its sole remedy for nonperformance by the other Party or other default by the other Party in the performance of its obligations under this Agreement shall be as specified in the Agreement. Both Parties agree to use commercially best efforts and actions to correct such nonperformance on their respective systems in a timely manner.

9. INDEMNIFICATION

Notwithstanding Paragraph 8 above, each Party shall indemnify the other Party including the agents, contractors, and employees of the Party, against all loss, damage, cost and expense (including attorneys' fees), judgment on other obligation or liability, resulting from physical injury to property or person, caused by the indemnifying Party's performance of its obligations under this Agreement; provided, however, that neither Party shall be obligated to indemnify the other Party against any loss, damage, cost, expense, liability, or cause of action which arises in whole or in part out of the sole negligence or willful misconduct of the other Party.

10. ASSIGNMENT

This Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and assigns; provided, however, that no Party shall assign or transfer this Agreement or any part thereof, or any right or obligation hereunder, without the written consent of the other Party, which may not be unreasonably withheld. Any such assignment which requires written consent hereunder, but which is made without such written consent, shall be null and void. Notwithstanding the above, assignment of the entire interest and obligations of the assigning Party may be made to a parent or affiliate of such assigning Party, or to an entity succeeding to all or substantially all of the business properties and assets of the assigning Party, following written notice to the other Party.

11. INFORMATION

Each Party shall have the right to request that the other Party provide information that is sufficient to verify the accuracy of any computation contemplated under this Agreement. All reasonable efforts shall be made by the Parties to resolve any disputed computations. Unresolved disputed computations may be submitted by either Party for resolution as described in Paragraph 13 of this Agreement. Notwithstanding the above, neither Party shall be required to provide the other Party with information that is confidential, proprietary, or in violation of the rules and regulations of either the FERC or CPUC.

12. FORCE MAJEURE

12.1 In the event either Party is rendered unable, wholly or in part, by force majeure (as defined in Paragraph 12.2) to carry out its respective obligations under this Agreement, it is agreed that, upon such Party giving notice and reasonably full particulars of such force majeure in writing or by telecopy or by telephone (and confirmed in writing within seventy-two [72] hours), to the other Party within a reasonable time after the occurrence of the cause relied on, then the obligations of the Party giving such notice, so far as they are affected by such force majeure, shall be suspended during the continuance of the effects of the cause, and the Party subject to such cause shall remedy it so far as possible with all reasonable dispatch.

12.2 The term "force majeure," as employed herein, shall mean an event or events beyond the reasonable control of a Party and shall include, but not be limited to, acts of God, strikes, lockouts or other industrial disturbances, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, high water, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakage or accident to machinery or lines of pipe, freezing lines of pipe, acts of civil or military authority (including, but not limited to, courts, or administrative or regulatory agencies). Such term shall likewise include (i) in those instances where any Party hereto is required to obtain servitudes, rights-of-way, grants, permits or licenses to enable such Party to fulfill its obligations hereunder, and such Party is unable to so acquire, is delayed in acquiring at reasonable costs and after the exercise of reasonable diligence, such servitudes, rights-of-way, grants, permits, certificates or licenses; and (ii) those instances where any Party hereto is required to furnish

materials and supplies for the purpose of constructing or maintaining facilities or is required to secure permits, or certificates of permission from any governmental agency to enable such Party to fulfill its obligations hereunder, and such Party is unable to so acquire, or is delayed in acquiring, at reasonable costs and after the exercise of reasonable diligence, such materials and supplies, permits and permissions. Failure of an administrative agency to authorize recovery of costs shall not constitute force majeure. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the Party having the difficulty, and the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of the opposing Party when such course is inadvisable in the discretion of the Party having the difficulty.

13. DISPUTE RESOLUTION

13.1 Within thirty (30) days of written notice from either Party to the other that there is a dispute, claim, or need for interpretation arising out of or relating to this Agreement, the Parties shall meet and attempt to reach an amicable settlement by negotiation. If the matter is not resolved within thirty (30) days of such meeting, the matter shall be resolved in the manner set forth in Paragraph 13.2 and 13.3, which shall be in lieu of litigation before any regulatory agency or in any state or federal courts.

13.2 At either Party's request, the Parties shall attempt to resolve their dispute through non-binding mediation in accordance with the Commercial Mediation Rules of the American Arbitration Association (AAA). The Parties shall establish specific ground rules for the mediation at least fourteen (14) days in advance of the mediation meeting. The mediation shall be held in Portland, Oregon, and shall commence within thirty (30) days of a Party's request for mediation. Each Party shall bear its own mediation costs. The costs and expenses of the mediator shall be divided equally between the Parties.

13.3 If no amicable settlement is reached as a result of the procedures prescribed in Paragraph 13.2, the matter shall be submitted to binding arbitration pursuant to the Commercial Arbitration Rules of the AAA (including any rules for expedition of the hearing process); provided, however, such rules shall be modified as necessary to reflect the following:

- a. Unless the Parties otherwise agree, the arbitration panel shall be composed of three persons. Each Party shall nominate one arbitrator, and the two arbitrators so appointed shall appoint a third, who shall act as the presiding arbitrator or chair of the panel. If either Party fails to nominate an arbitrator within thirty (30) days of receiving notice of the nomination of an arbitrator by the other Party, such (second) arbitrator shall be appointed by the AAA at the request of the first Party. If the two arbitrators so selected fail to select a third presiding arbitrator, the third arbitrator shall be appointed by the AAA. Should a vacancy occur on the panel, it shall be filled by the method by which that arbitrator was originally selected.
- b. The arbitration shall be held at a location to be agreed by the Parties, or, failing such an agreement, at San Francisco, California.
- c. The arbitrators shall hold a preliminary meeting with the Parties within thirty (30) days of the appointment of the third or presiding arbitrator for the purpose of determining or clarifying the issues to be decided in the arbitration, the specified procedures to be followed, and the schedule for briefing and/or hearings. The arbitrators shall hold a hearing and, within one hundred and twenty (120) days of the preliminary meeting (except in extraordinary cases) shall issue a written decision and include findings of fact and conclusions of law.
- d. Such decision shall thereafter be deemed to be part of this Agreement and incorporated by reference herein.
- e. Pending such decision, the Parties shall continue to operate under the Agreement; however, the decision by the panel should consider specifically the appropriateness of retroactive adjustments to the date the dispute first arose.
- f. The United States District Court for the Northern District of California or a Superior Court of the State of California may enter judgment upon the panel's

decision, either by confirming the decision or by vacating, modifying, or correcting the decision. The Court may vacate, modify, or correct any such decision only: (i) if there exists any of the grounds referred to in the United States Arbitration Act, or (ii) to the extent that the panel's conclusions of law are erroneous.

g. The allocation of costs of arbitration shall be considered and determined by the panel in connection with its decision, and, for example, the entire costs of such proceeding, including reasonable attorneys fees (for in-house and outside counsel) may be awarded to the prevailing Party.

h. Neither Party shall be assessed any punitive damages.

i. In the event it is necessary to enforce an arbitration award, all costs of enforcement, including reasonable attorney fees (for in-house and outside counsel), shall be payable to the prevailing Party.

13.4 The resolution of disputes subject to this Section 13 shall be governed by, and the arbitrators shall render their decision in accordance with, the substantive laws of the State of California, without regard to its choice of law rules.

14. NOTICE

14.1 Any notice, request, demand, or statement provided for in this Agreement shall be in writing and deemed given when deposited in the United States mail, postage prepaid, directed to the post office address of the Parties as follows:

AGREEMENT NOTICES AND OTHER CORRESPONDENCE

Pacific Gas Transmission Company
2100 S.W. River Parkway
Portland, OR 97201
Telephone: (503) 833-4000
Telecopier: (503) 833-4332
Attn. Manager of Transportation

Pacific Gas and Electric Company
245 Market Street, Room 1503, N15A
P.O. Box 770000
San Francisco, CA 94177
Telephone: (415) 973-2908
Telecopier: (415) 973-9247
Attn. Business Projects

DISPATCHING AND NOMINATIONS

Pacific Gas Transmission Company
2100 S.W. River Parkway
Portland, OR 97201
Dispatch Telephone: (503) 833-4200
Telecopier: (503) 833-4395
Nominations: (503) 833-4300

Pacific Gas and Electric Company
77 Beale Street, Room 1643, B16A
P.O. Box 770000
San Francisco, CA 94177
Dispatch Telephone: (415) 973-3214
Nominations: (415) 973-3220
Telecopier: (415) 973-0649

14.2 Either Party may from time-to-time change or designate another address for such purposes upon thirty (30) calendar days prior written notice by the Party requesting such change.

14.3 Notices, requests, and demands may also be given by facsimile or other electronic transmittal provided that such facsimile or electronically conveyed notice, request or demand is confirmed in writing delivered as aforesaid within three (3) business Days of receipt of facsimile or other electronic notice. Notice regarding routine operations may be exclusively communicated by facsimile or other electronic means. All nominations and such confirmations must be made via electronic data exchange when such systems are operational.

15. CONFIDENTIALITY

Each Party agrees that it will maintain this Agreement, and all parts and contents thereof in strict confidence, and that it will not cause or permit disclosure of same to any third party without the express written consent of the other Party; provided however, that disclosure by a Party is permitted in the event and to the extent (i) such disclosure is required by a court or agency exercising jurisdiction over the subject matter hereof, by order or by regulation (provided that in the event either Party becomes aware of a judicial or administrative proceeding that has resulted in an order requiring disclosure, or in which any party to such proceeding has sought

such an order, it shall so notify the other Party immediately); (ii) disclosure is necessary to agents, contractors, and employees for the proper prosecution of their work; or (iii) disclosure is necessary in connection with a bona fide sale or assignment of an interest in this Agreement, the borrowing of funds, obtaining of insurance, and/or sale of securities. In such event the disclosing Party shall notify the other Party of the name of such third party and the nature of such disclosure prior to the disclosure.

16. ADDITIONAL PROVISIONS

16.1 No consent or waiver, expressed or implied, by either Party of any breach or default by the other Party in the performance of its obligations hereunder shall be deemed or construed to be a consent to or waiver of any other breach or default in the performance of any other obligation of the other Party. Failure on the part of either Party to complain of any act or failure to act by the other party or to declare the other Party in default, regardless of how long such failure continues, shall not constitute a waiver by such Party of any of its rights hereunder.

16.2 This Agreement supersedes all prior agreements, representations and understandings, written or oral, pertaining to the subject matter herein.

16.3 THIS AGREEMENT AND THE OBLIGATION OF THE PARTIES HEREUNDER SHALL BE INTERPRETED, CONSTRUED AND CONTROLLED BY THE LAWS OF THE STATE OF CALIFORNIA.

16.4 This Agreement was jointly negotiated, and any ambiguities or uncertainties in the wording of this Agreement shall not be construed for or against either Party, but shall be construed in a manner which most accurately reflects the intent of the Parties when this Agreement was executed.

16.5 This Agreement may be amended only by an instrument in writing executed by both Parties hereto.

16.6 Each Party shall do all necessary acts and make, execute, and deliver such written instruments as shall from time to time be reasonably necessary to carry out the terms of this Agreement.

16.7 Whenever the context may require, the singular form of nouns, pronouns and verbs shall include the plural and vice versa.

16.8 The descriptive headings of all paragraphs of this Agreement are formulated and used for convenience only and shall not be deemed to affect the meaning or construction of any such paragraphs.

16.9 Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to that jurisdiction, be ineffective to the extent of that prohibition or unenforceability without invalidating the remaining provisions hereof or affecting the validity or enforceability of that provision in any other jurisdiction.

16.10 PGT's general Terms and Conditions of its FERC approval Gas Tariff, First Revised Volume No. 1A, and subsequent changes or revisions, are by reference made a part hereof.

16.11 PG&E's Rule 21, as approved by the CPUC and any subsequent changes or revisions, is by reference made a part hereof.

16.12 The parties agree that changes ordered by the FERC to any of the operating procedures established under this Agreement shall be made in writing as an amendment within sixty (60) days of such FERC order(s).

16.13 This Agreement is intended solely for the benefit of the Parties and their permitted successors and assigns and, except as may be specifically set forth herein, is not intended to and shall not confer rights or benefits upon any other party.

IN WITNESS WHEREOF, the Parties have, through this duly authorized officers or employees, executed this agreement as of the date herein above written.

PACIFIC GAS AND ELECTRIC COMPANY

By: H. O. LAFLASH

H. O. LaFlash Manager, Business Projects

Date: 7/9/96

PACIFIC GAS TRANSMISSION COMPANY

By: PETER LUND

Peter Lund Vice President, Marketing & Transportation

Date: 7/2/96

EXHIBIT 10.6

PG&E-TRANS(SM) USER AGREEMENT

This is a user agreement (hereafter the "Agreement") dated November 15, 1999, between PG&E GAS TRANSMISSION, NORTHWEST CORPORATION (hereafter "PG&E GT-NW"), and Pacific Gas & Electric Co. (hereafter the "User"), for the use of PG&E GT-NW's on-line services for conducting gas transportation and storage related business, including PG&E-trans(SM), PG&E-trans(SM)nw, and PG&E-trans(SM)northwest (hereafter collectively referred to as "PG&E-trans(SM)").

WHEREAS, access to PG&E-trans(SM) benefits User and is an integral part of the provision of on-line services through the global communications network by PG&E GT-NW, providing functions formerly accessible only upon PG&E GT-NW's Pacific Trail(R) Electronic Bulletin Board Service; and

WHEREAS, User desires to access and use PG&E-trans(SM), and bind itself to reasonable terms and conditions of such access and use; and

WHEREAS, User desires to submit nominations of gas to PG&E GT-NW under applicable tariffs and such other available applications, current or future, deemed necessary and made available by PG&E GT-NW through PG&E-trans(SM); and

WHEREAS, User understands that by using PG&E-trans(SM), it may enter into binding agreements with third parties;

NOW, THEREFORE, the parties intending to be legally bound, agree as follows:

1. User understands and agrees that it may bind itself contractually to other users of PG&E-trans(SM) during the course of operating the natural gas posting or remarketing functions of the PG&E-trans(SM) system. User agrees that approving, agreeing to, or entering a transaction as provided by PG&E-trans(SM), as it now exists, or may in the future be modified, and subject to applicable tariffs, shall constitute a written contract (a "Contract"). By executing this Agreement, User agrees that it adopts any confirmation of a Contract as provided by PG&E-trans(SM) as User's signature, and such confirmation will, together with this Agreement, constitute an executed writing. User agrees to waive any Statute of Frauds defense to the enforceability of any Contract arising from use of PG&E-trans(SM). User agrees and warrants that any employee or agent of User using PG&E-trans(SM) shall have all necessary power and authority to use PG&E-trans(SM) and enter Contracts as herein provided. User warrants for itself, its successors and assigns that for each Contract that User may enter as a result of using PG&E-trans(SM), User shall have all right, title, power and authority necessary to honor said Contract.

PG&E-TRANS(SM) IS A SERVICE MARK OF PG&E CORPORATION.

PACIFIC TRAIL(R) IS A REGISTERED TRADEMARK OF PG&E GAS TRANSMISSION, NORTHWEST CORPORATION.

PG&E Gas Transmission-Northwest and any other company referenced herein which uses the PG&E name or logo are not the same company as Pacific Gas and Electric Company, the California utility; neither PG&E Gas Transmission, Northwest Corporation, nor these other referenced companies are regulated by the California Public Utilities Commission, and customers do not have to buy products from these companies in order to receive quality regulated services from the utility.

1.1 User and PG&E GT-NW agree that this paragraph 1 is intended to benefit users accessing PG&E-trans(SM), and that such other users are third-party beneficiaries of said paragraph 1. User and PG&E GT-NW do not intend hereby that other users are or will be third-party beneficiaries of any other provisions of this Agreement.

2. User agrees that it shall be bound by all the terms and conditions of this Agreement, as well as any and all applicable tariffs currently in effect for PG&E GT-NW as approved by the Federal Energy Regulatory Commission ("FERC"), or which may hereafter be implemented. Such tariffs are matters of public record, which User warrants it has reviewed and will review in the future. User further agrees that PG&E GT-NW may modify or limit PG&E-trans(SM) at any time and without notice. From time to time, PG&E GT-NW may, at its sole discretion, develop updates or enhancements to the existing functionality of PG&E-trans(SM). If an update or enhancement is released to PG&E-trans(SM), such update or enhancement will be subject to the terms of this Agreement. PG&E GT-NW shall be under no obligation to provide any such updates or enhancements.

3. PG&E GT-NW may terminate PG&E-trans(SM) and provide alternative electronic bulletin board access at any time in accordance with its tariffs, and may further terminate this Agreement with User, upon written notice by PG&E GT-NW, for cause, including failure to honor this Agreement, including applicable tariffs, failure to honor any Agreement entered through PG&E-trans(SM), PG&E GT-NW's Pacific Trail(R) Electronic Bulletin Board Service, or applicable PG&E GT-NW Electronic Data Interchange Trading Partner Agreement, failure to pay required reservation or demand charges, or failure to meet PG&E GT-NW's applicable credit requirements. Either party may terminate this Agreement upon thirty (30) days' notice, but no such termination (whether for cause or otherwise) shall affect User's obligation for Contracts entered during its use of PG&E-trans(SM). Without limiting other remedies, PG&E GT-NW may immediately issue a warning, temporarily suspend, indefinitely suspend or terminate this Agreement with User and refuse to provide access to PG&E-trans(SM) if PG&E GT-NW believes that User's actions may cause legal liability for User, third persons or PG&E GT-NW.

4. User acknowledges that any submission under PG&E-trans(SM) may be subject to a credit review and approval requirement as may be applicable under PG&E GT-NW tariffs. User further acknowledges that it may not exceed its previously determined credit limit with respect to any bid. PG&E GT-NW may treat any bid that exceeds User's previously determined credit limit, at PG&E GT-NW's option, as a bid in an amount equal to the User's previously determined credit limit, or it may regard such a bid as void and of no effect.

5. This Agreement shall become effective on the date first above written. Unless earlier terminated as provided in paragraph 3, this Agreement shall continue in effect for five (5) years thereafter, and shall automatically continue for succeeding five (5) year terms unless canceled by PG&E GT-NW at least thirty (30) days before the expiration of each such term.

6. If either party hereto shall fail to perform any obligation imposed upon it by this Agreement, and such failure shall be caused, or materially contributed to, by "force majeure," which means any act of God, strikes, lockouts, or other industrial disturbances, acts of public enemies, sabotage (whether or not performed by persons affiliated with parties hereto), wars, blockades, insurrections, riots, epidemics, landslides, lightning, electrical power failures, telecommunication system failures, earthquakes, floods, storms, fires, washouts, extreme cold or freezing weather, arrests and restraints of rulers or people, civil disturbances, explosions, breakage of or accident to machinery or lines of pipe, materials or equipment, computer hardware or software failure, legislative, administrative or judicial action which has been resisted in good faith by all reasonable legal means, any acts, omissions or causes whether of the kind herein enumerated or otherwise not reasonably within the control of the party invoking this paragraph and which by the exercise of due diligence such party could not have prevented the necessity for making repairs to, replacing, or reconditioning machinery, hardware, software, equipment, or pipelines, not resulting from the fault or negligence of the party invoking this paragraph, such failure shall be deemed not to be a breach of the obligation of such party, but such party shall use reasonable diligence to put itself in a position to carry out its obligations.

6.1 Nothing contained herein shall be construed to require either party to settle a strike or lockout by agreeing against its judgment to the demands of the opposing parties. No such cause as described in paragraph 6 affecting the performance of either party shall continue to relieve such party from its obligation after the expiration of a reasonable period of time within which by the use of due diligence such party could have remedied the situation preventing its performance, nor shall any such cause relieve either party from any obligation unless such party shall give notice thereof in writing to the other party with reasonable promptness; and like notice shall be given upon termination of such cause. Further, inasmuch as this Agreement relates solely to PG&E-trans(SM), no such cause as described in paragraph 6 shall, by the force of this Agreement, have any effect on other agreements or tariffs affecting the parties; specifically, no such cause as described in paragraph 6 shall affect User's obligation to pay any demand charges otherwise due to PG&E GT-NW.

7. User agrees to defend, indemnify and hold harmless PG&E GT-NW, its officers, agents and employees against any liability, loss or damage whatsoever occurring in connection with or relating in any way to this Agreement or the use of PG&E-trans(SM), including costs and attorneys' fees, (where such liability, loss or damage results from any demand, claim, action, cause of action, or suit brought by User or by any person, association or entity, public or private, that is not a party to this Agreement) to the extent such liability, loss or damage is a direct or indirect result of any breach by User of this Agreement, or is a direct or indirect result of any sole or concurrent negligence or other tortious acts or omissions by User, its officers, agents or employees in the performance of this Agreement or through its use of PG&E-trans(SM).

8. User acknowledges that use of PG&E-trans(SM) by User involves transmission over the global communications network or Internet of proprietary and confidential information of User. PG&E GT-NW cannot guarantee the security of such information during its transmission by User over the global communications network or Internet. PG&E GT-NW will not be liable or responsible in any way to User for any losses, damages, claims, costs, expenses or other obligations arising out of or relating to any unauthorized access to or disclosure or use of such information transmitted over the global communications network or Internet. User further acknowledges and agrees that User is solely responsible for the accuracy of all information and data that User transmits to PG&E GT-NW, and PG&E GT-NW shall not be liable for any such inaccuracies.

9. PG&E GT-NW does not represent or warrant that PG&E-trans(SM) will be uninterrupted or error-free, that defects will be corrected, or that PG&E-trans(SM) or the server that makes it available, are free of viruses or other harmful components. PG&E GT-NW does not warrant or represent that the use or the results of the use of PG&E-trans(SM) or the materials made available as part of PG&E-trans(SM) will be correct, accurate, timely, or otherwise reliable.

User specifically agrees that PG&E GT-NW shall not be responsible for unauthorized access to or alteration of User's transmissions or data, any material or data sent or received or not sent or received, or any transactions entered into or through PG&E-trans(SM). User specifically agrees that PG&E GT-NW is not responsible or liable for any threatening, defamatory, obscene, offensive or illegal content or conduct of any other party or any infringement of another's rights, including intellectual property rights.

PG&E GT-NW MAKES NO REPRESENTATIONS ABOUT THE SUITABILITY, RELIABILITY, AVAILABILITY, TIMELINESS, AND ACCURACY OF PG&E-TRANS(SM) FOR ANY PURPOSE. PG&E-TRANS(SM) IS PROVIDED "AS IS" WITHOUT WARRANTY OF ANY KIND. PG&E GT-NW HEREBY DISCLAIMS ALL WARRANTIES AND CONDITIONS WITH REGARD TO PG&E-TRANS(SM), INCLUDING ALL IMPLIED WARRANTIES AND CONDITIONS OF MERCHANTABILITY, FITNESS FOR A PARTICULAR PURPOSE, TITLE AND NON-INFRINGEMENT.

10. Neither party shall be liable to the other for any special, incidental, exemplary or consequential damages arising from or as a result of any delay, omission or error in the electronic transmission or receipt of any information or data pursuant to this Agreement, or arising out of or in any way connected with the use or performance of PG&E-trans(SM) or related web sites, even if the other party has been advised of the possibility of such damages and regardless of negligence or fault.

11. User agrees that the laws of the State of Oregon, without giving effect to choice of law provisions, shall govern the interpretation and enforcement of this Agreement. Any dispute or controversy arising from this Agreement or from PG&E GT-NW's operation of PG&E-trans (SM), whether arising in tort, contract or otherwise, shall be resolved as

provided in this paragraph 11. During the process of dispute resolution, the parties shall continue performance of their respective obligations under the Agreement.

11.1 Prior to resorting to mediation or arbitration, the parties agree to consult about any differences they may have under the Agreement.

11.2 If the parties are unable to agree after consultation, either party may request, in writing, that mediation be undertaken to attempt to reach agreement. The parties agree to attempt to mediate their dispute through the selection of a mutually acceptable neutral mediator upon such terms and conditions as they might agree. Each party agrees to pay their own costs associated with mediation and each agrees to pay one-half of the fees of the mediator.

11.3 If, after the period of thirty (30) days from the date of the written notice requesting mediation, the parties are unable to reach agreement through mediation, either party may call for binding arbitration. Arbitration proceedings shall take place in Portland, Oregon. The party calling for arbitration shall serve notice in writing upon the other party, setting forth in detail the question or questions to be arbitrated. The party calling for arbitration shall, as part of its notice, propose an arbitrator. The other party shall, within ten (10) days after the receipt of such notice either agree to the proposed arbitrator or reject the proposed arbitrator and may propose an alternative arbitrator. If the alternative proposed arbitrator is rejected, or the responding party refuses to propose an arbitrator after ten (10) days, the party calling for arbitration shall notify the Chief Judge of the United States District Court for the District of Oregon and request that he or she appoint an arbitrator qualified in matters related to the interstate transportation of natural gas.

11.4 The arbitrator shall apply applicable provisions of Oregon law and the commercial arbitration rules of the American Arbitration Association (to the extent consistent with the procedures provided for herein) in reaching his or her determination. The arbitrator shall make a determination within sixty (60) days of the arbitrator's appointment.

11.5 The determination by the arbitrator shall be binding on the parties. The losing party shall pay all costs of the arbitrator including fees and expenses. The prevailing party shall be entitled to reasonable attorney's fees, costs and expenses, including compensation for witnesses or consultants, incurred in the arbitration.

11.6 The award of the arbitrator shall be drawn up in writing and signed by the arbitrator and shall be final and binding on both PG&E GT-NW and User, and PG&E GT-NW and User shall abide by the award and perform the terms and conditions thereof. Unless otherwise determined by the arbitrator, the fees and expenses of the arbitrator shall be paid in equal proportion by PG&E GT-NW and User.

12. No waiver by either PG&E GT-NW or User of any default by the other in the performance of any provisions of this Agreement shall operate as a waiver of any continuing or future default, whether of a like or different character.

13. PG&E GT-NW shall not be required to perform or continue PG&E-trans(SM) on behalf of any User that fails to comply with the terms contained in this Agreement, including applicable tariffs.

14. PG&E GT-NW will provide User with a unique identification code, password and, in some cases depending upon the nature of User's access rights, a signature code, each of which shall be unique to each of User's authorized employees and without which User may not access PG&E-trans(SM). User shall complete an executed Appendix B for each of User's employees as designated by User for PG&E-trans(SM) access. User shall take all measures to maintain the secrecy and confidentiality of the password, identification code and, if applicable, signature code, to be provided to User. User acknowledges that a change in its password, identification code, or signature code may only be obtained from PG&E GT-NW by User's submission of a written request on Appendix B. User is entirely responsible for maintaining the confidentiality of its password, identification code and, if applicable, signature code (collectively "access codes") that uniquely identify the User and the employee authorized to act on behalf of the User. Furthermore, User is entirely responsible for any and all activities that occur under its account using the access codes. User acknowledges that it may, from time to time, terminate employees with knowledge of the access codes and agrees to take all steps to change one or more of the access codes to protect against unauthorized use of its account by submitting a revised Appendix B for that employee. User further agrees to notify PG&E GT-NW immediately of any unauthorized use of its account or any other breach of security. User acknowledges and consents that PG&E GT-NW, as the system operator and owner of PG&E-trans(SM), shall have access to, and the ability to review to the fullest extent allowed by law, all messages, electronic mail, files and other communications of any sort on PG&E-trans(SM), whether or not such communications are designated as private or confidential.

15. User agrees to exercise due and reasonable care in the use of PG&E-trans(SM). User is solely responsible for obtaining all hardware, software, telecommunications lines and Internet or global communications network access that may be required to access PG&E-trans(SM).

16. User acknowledges that PG&E GT-NW is the owner of all intellectual property rights to PG&E-trans(SM). PG&E-trans(SM) is intended for the posting, remarketing, and management of natural gas transportation and storage capacity on the natural gas pipeline owned by PG&E GT-NW. User understands that PG&E GT-NW is making access to PG&E-trans(SM) available to User for no direct charge, except for telephone or Internet access charges, which remain User's responsibility.

17. In the event that User requests additional services or alternative access relating to PG&E-trans(SM), the parties may mutually agree on the pricing for such services in a separate

agreement. Any such additional services or alternative access relating to PG&E-trans(SM) are otherwise subject to the terms of this User Agreement.

18. User agrees that PG&E GT-NW has extended access to PG&E-trans(SM) to User because of the specific business relationship between User and PG&E GT-NW, and in some cases because of User's particular credit history. This personal Agreement between User and PG&E GT-NW may not be assigned by User without the prior consent of PG&E GT-NW, which consent shall not unreasonably be withheld.

19. All notices required or permitted to be given with respect to this Agreement shall be given by mailing the same postage prepaid, or given by facsimile or by courier, to the addressee party at such party's address as set forth in Appendix A. Either party may change its address for the purpose of notice hereunder by giving the other party no less than five (5) days' prior written notice of such new address in accordance with the preceding provisions.

20. This Agreement may be executed in any number of original counterparts, all of which shall constitute one and the same instrument.

21. Any provision of this Agreement that is determined to be invalid or unenforceable will be ineffective to the extent of such determination without invalidating the remaining provisions of this Agreement or affecting the validity or enforceability of such remaining provisions.

PG&E GAS TRANSMISSION,
NORTHWEST CORPORATION

By: JAMES E. ROBBINS

Name: James E. Robbins

Title: Director, Market Services

PACIFIC GAS & ELECTRIC CO.
(PG&E CORE)

By: E. JAMES MACIAS

Name: E. James Macias

Title: SVP & General Mgr, GT&S

(MUST BE SIGNED BY AN
OFFICER OF THE
COMPANY)

APPENDIX A

ADDRESS FOR NOTICE

If to PG&E GT-NW:

PG&E Gas Transmission, Northwest Corporation 2100 S.W. River Parkway Portland, Oregon 97201

Telephone:	(503) 833-4301
Facsimile:	(503) 833-4900
Attention:	James E. Robbins

If to User:

Name:	Pacific Gas & Electric Co. (PG&E CORE)
Address:	77 Beale Street - M/C B5F
	San Francisco, CA 94105
Telephone:	(415) 973-9035
Facsimile:	(415) 973-9213
Attention:	David W. Clare

EXHIBIT 10.7

Pacific Gas and Electric Company

Electronic Commerce System

User Agreement

This agreement ("Agreement") is between Pacific Gas and Electric Company ("PG&E"), and the party identified below (hereafter "User").

WHEREAS, PG&E has established an electronic commerce system and one or more websites or other Internet-based electronic transaction and scheduling facilities (and may establish additional such facilities). (The electronic commerce system, website(s) and facilities are referred to herein collectively as the "ECS.") Included in the ECS is the capability to do the following transactions: enter into a Gas Transmission Service Agreement ("GTSA") and Exhibits thereto; enter into a Noncore Balancing Aggregation Agreement ("NBAA"); conduct natural gas pipeline related business, and trade on the California Gas Transmission ("CGT") Trading Platform, including without limitation: (i) obtaining natural gas transportation, storage, parking and lending services provided pursuant to a GTSA on the PG&E natural gas pipeline system (collectively "Service Transactions"); (ii) scheduling of such services ("Scheduling Transactions"); (iii) trading of natural gas imbalances; and (iv) on-line accessing of pipeline related information. (The Service Transactions and Scheduling Transactions are also collectively referred to herein as "Transactions.")

WHEREAS, User desires to access and use the ECS; and PG&E is willing to provide such access subject to the terms and conditions set forth herein.

NOW THEREFORE, for consideration, the receipt and adequacy of which are hereby acknowledged, the parties intending to be legally bound, agree as follows:

1. ACCESS AND USE CONDITIONS

After execution of this Agreement, and subject to its terms and conditions, PG&E agrees to provide User with on-line access to the ECS, and User understands and agrees to the following:

1.1. User shall complete and execute the "Access Request Form," attached hereto as Exhibit B, identifying authorized employees or agents of User, designated by User to access and use the ECS and execute transactions on behalf of User. PG&E will issue to User an identification code ("User ID") for each of User's employees and agents identified on Exhibit B, to enable User to access and use the ECS. Any and all use and/or access of the ECS with any of the User IDs issued to User shall be deemed and construed to be use or access by User. User shall strictly limit the use of the User IDs to those employees and agents of User who are identified on Exhibit B. User shall immediately notify PG&E when

an individual identified on Exhibit B ceases to be authorized by User to use his or her User ID, by submitting a modified Exhibit B to PG&E.

1.2. User shall take all measures to maintain the confidentiality of the User IDs and of all passwords used to access the ECS ("Passwords"). User shall be solely responsible for the assignment, security and use of the User IDs and Passwords and the control and monitoring of such use. PG&E shall have no responsibility for any of the foregoing and no liability for or arising from the use of the User IDs or Passwords by anyone. User shall be solely responsible and liable for any and all acts and omissions with respect to access or use of the ECS by anyone using the User IDs, including, but not limited to, the execution of Transactions.

1.3. User agrees to indemnify and hold PG&E harmless from and against all damages, losses, and liabilities arising out of or in connection with any breach of confidentiality, misuse or unauthorized use of any User ID issued by PG&E to User, regardless of whether User has notified PG&E as required by paragraph 1.1 above.

1.4. User will access and use the ECS (including, but not limited to, execution of Transactions) solely for its own internal business purposes and in accordance with the terms and conditions of this Agreement, any procedures established by PG&E with respect to the access or use of the ECS and any other terms and conditions specified or referred to on the ECS from time to time. User understands and agrees that User's use of the ECS may be limited or modified by the terms of licenses or other agreements between PG&E and third parties. User further agrees that PG&E may modify or limit the use of the ECS at any time and without notice. PG&E may, in its sole discretion, terminate, restrict, or suspend User's access to and use of the ECS.

1.5. User acknowledges that use of the ECS by User involves transmission over the worldwide communications network or Internet of proprietary, confidential and/or time sensitive information of User. User understands the risks associated with the transmission of such information by User over the worldwide communications network or Internet. User agrees that PG&E shall not be liable or responsible in any way to User for any losses, damages, claims, costs, expenses or other obligations arising out of or relating to any delay in transmission, disclosure or use of such information or data transmitted over the worldwide communications network or Internet. User further acknowledges and agrees that User is solely responsible for the accuracy of all information and data that User transmits to PG&E, and PG&E shall not be responsible or liable for any such inaccuracies or their effects.

1.6. User further agrees that PG&E shall not be responsible for delays in sending or receiving User's transmissions or data, for unauthorized access to or alteration of User's transmissions or data, any transmission, information or data sent or received or not sent or received, or any Transactions entered into or through the

ECS. User specifically agrees that PG&E is not responsible or liable for any threatening, defamatory, obscene, offensive or illegal content or conduct of any other party or any infringement of any other party's rights, including intellectual property rights.

1.7. User understands and agrees that (i) User is solely responsible for acquiring and ensuring that it possesses sufficient Internet access speed capability to adequately conduct business on the ECS, and (ii) User shall be solely responsible for all costs associated with its accessing and using the ECS.

1.8. User acknowledges and consents that PG&E, as the ECS operator, shall have access to and the right to review, to the fullest extent allowed by law, files and other communication of any sort on the ECS whether or not such communications are designated as private or confidential.

2. BINDING CONTRACTS

User acknowledges that by using the ECS, it may enter into binding contracts with PG&E and with third parties. User agrees that (i) any and all access or use of the ECS using the User IDs will be governed by this Agreement; (ii) any nomination or offer placed, any contract terms, conditions or exhibits accepted or confirmed, and any Transaction executed, on the ECS will be deemed to be "in writing," to have been signed," or be an "executed" writing; and (iii) accepting or entering into a Transaction by using the ECS, as it now exists or may in the future be modified, and subject to applicable tariffs, shall constitute a written contract (a "Contract"). With limitation of the foregoing, User agrees that it will be bound by any and all contract terms and conditions, including, but not limited to, the GTSA and NBAA, and by any and all nominations, offer, trades, or other Transactions executed, accepted or confirmed on the ECS through a "click" agreement by any individual using the User ID. By executing this Agreement, User agrees that it adopts as User's signature any such "click agreement," defined for purposes of this Agreement as "clicking" on the designated space on the ECS (or other action on the ECS specified by PG&E), and such "click agreement" will, together with this Agreement, constitute an executed writing. User agrees to waive any Statute of Frauds defense to the enforceability of any Contract arising from use of the ECS. User agrees and warrants that any employee or agent of User using the ECS shall have all necessary power and authority to use the ECS and enter into Transactions as herein provided. User warrants for itself and its successors and assigns that for each Transaction that User may enter into by using the ECS, User shall have all right, title, power and authority necessary to honor that Contract.

2.1. User and PG&E agree that this Article 2 is intended to benefit other users accessing the ECS, and that such other users are third party beneficiaries of this Article 2. User and PG&E do not intend hereby that other users are or will be third party beneficiaries of any other provisions of this Agreement.

3. APPLICABLE TARIFFS, TERMS AND CONDITIONS

User agrees that it shall be bound by all the terms and conditions of this Agreement, the terms and conditions accepted on the ECS by a click agreement in accordance with Article 2 above, as well as any and all applicable tariffs currently in effect for PG&E as approved by the California Public Utilities Commission ("CPUC") and/or the Federal Energy Regulatory Commission ("FERC"), or which may hereafter be implemented, and all amendments thereof. Such tariffs are matters of public record, which User represents that it has reviewed and will review in the future.

4. TRANSACTIONS AND CONFIRMATIONS

4.1. After User has received the User ID(s) and has executed the applicable contracts (and subject to applicable tariffs), User may enter into Transactions, including service elections under a GTSA executed by User ("User GTSA"), as follows:

4.1.1. GTSA Service Elections: User shall enter into Transactions, i.e., elect services under User's GTSA, including Gold Coast Transportation Services, Golden Gate Market Center Services, and Storage Services, and PG&E may accept and authorize such service elections, by following the procedures set forth in paragraph 4.1.2 of this Agreement. Such procedures in paragraph 4.1.2 shall be used instead of the procedures set forth in the User GTSA providing that a service election shall be entered into through, and evidenced by, a "hard copy" of Exhibits A through I (Form No. 79-866), or any one of them; and providing for a written signature by User and countersignature by PG&E to such Exhibits A through I.

4.1.2. Service Transaction: User may telephone a PG&E CGT Representative to enter into a Service Transaction.

PG&E may accept or reject User's offer or order in PG&E's sole discretion. Service Transactions shall be deemed executed at the time that PG&E first signifies its acceptance of User's offer or order, which in most instances will occur when User enters into a Transaction with PG&E orally by telephone, as documented by an audio recording. The audio recording of Transactions between User and PG&E shall constitute evidence of such Transactions, and User hereby consents to the recording of all Transactions between User and PG&E.

After User and PG&E have entered into a Service Transaction orally by telephone, PG&E will provide notice to User by e-mail that an electronic exhibit confirming the specific business terms of that Service Transaction are posted on the ECS (the "Electronic Exhibit"). The terms of the Electronic Exhibit shall be valid and binding on User, unless User deems any of the terms of the Electronic Exhibit to be stated incorrectly

and notifies PG&E of the incorrect term(s) as soon as possible but no later than within five (5) business days (the "Response Period") following receipt of the e-mail notice. If PG&E and User disagree as to the correct terms of the Electronic Exhibit, the audio recording of the transaction shall prevail and shall constitute evidence of the Transaction and its term. If the term or terms in dispute cannot be determined from such recording, and the parties do not resolve the dispute within two (2) business days, the Transaction shall be deemed void. Notwithstanding the foregoing, if User does not notify PG&E of an error in the Exhibit within the Response Period, or if User nominates, takes delivery, or performs any other act indicating performance of or under the Service Transaction, the Electronic Exhibit shall be deemed confirmed by User, absent an obvious error in the Electronic Exhibit.

4.1.3. Scheduling Transactions: After User has executed any necessary Service Transactions, User may submit nominations for transportation, parking, lending, storage and other services, on-line, using the ECS.

4.1.4. Imbalance Trading: User may utilize the ECS, subject to the terms, conditions, and limitations of this Agreement, to confirm a trade, or to confirm a trade with another User, of operating or cumulative imbalances, as those are defined and specified in PG&E's CPUC-approved rate Schedule G-BAL. User acknowledges that such trades do not involve PG&E as a party to the trade. User agrees that it may enter into such trades as set forth in Schedule G-BAL and may utilize the ECS to confirm the trade and to notify PG&E of the trade, provided, however, that User strictly follows the protocols, directions and rules for confirming trades as set forth in the ECS.

5. FEES AND TERMS OF PAYMENT

5.1. User understands that initially (and subject to the provisions of this Article 5) PG&E is making access to the ECS available to User for no direct charge, except for telephone access charges and any Internet access fees, which shall be and remain User's responsibility.

5.2. PG&E reserves the right to initiate and/or modify fees for the use of the ECS, subject to Commission approval. User has the right to discontinue use of the ECS at that time or continue using the ECS subject to such fees.

6. TITLE AND RIGHTS TO ECS, INFORMATION AND SERVICES

6.1. User acknowledges that PG&E and its licensors are the owners of all intellectual property rights in and to the ECS, the software used in connection therewith, and all information contained thereon or related thereto, and User shall have no right, title, or interest in any of these.

6.2. User shall not copy, reverse-engineer, modify, or otherwise manipulate, or make available to any other party, all or any portion of the ECS or any software or information provided or accessed in connection with the ECS.

6.3. PG&E shall have the right to modify the ECS, User IDs, software, or communication access, and to terminate access to any or all of these, at any time. In the event of such a termination or modification, or termination of this Agreement pursuant to Article 7 below, PG&E shall not be liable for any costs, losses or damages, including, but not limited to, lost profits or revenues.

7. TERMINATION

7.1. This Agreement shall become effective on the date of its execution by PG&E and shall remain in effect until terminated as provided herein.

7.2. Either party may terminate this Agreement at its sole discretion by giving the other party at least thirty (30) days' prior written notice.

7.3. PG&E may terminate this Agreement immediately if User breaches this Agreement and does not cure the breach within fourteen (14) days of receipt of a written notice from PG&E, or if User fails to pay any required charges when due, fails to meet PG&E's applicable credit requirements, or fails to comply with the provisions of any tariff or any other contract entered into in connection with the ECS or this Agreement.

7.4. Upon the termination of this Agreement, PG&E will terminate User's access to the ECS and User shall discontinue using the software manuals, and other items ("Property" of PG&E or third parties) in User's possession and shall destroy all such Property, if any is in User's possession.

7.5. The provisions of Paragraphs 7.3 and 7.4, and Articles 6, 8 and 10 shall survive termination of this Agreement by either party; and all articles or paragraphs of this Agreement which by their nature are intended to survive termination or expiration of this Agreement shall also survive. This Agreement shall also remain in effect with respect to any transactions effected prior to such termination.

8. DISCLAIMER OF WARRANTIES, LIMITATION OF LIABILITY AND INDEMNIFICATION

8.1. PG&E DOES NOT REPRESENT OR WARRANT THAT THE ECS OR ITS USE WILL BE UNINTERRUPTED OR FREE OF DEFECTS, ERRORS OR MALFUNCTIONS, OR THAT DEFECTS WILL BE CORRECTED, OR THAT THE ECS OR THE SERVER THAT MAKES IT AVAILABLE, ARE FREE OF VIRUSES OR OTHER HARMFUL COMPONENTS. PG&E DOES NOT WARRANT OR REPRESENT THAT THE USE OR THE RESULTS OF THE

**USE OF THE ECS OR THE TRANSACTIONS MADE AVAILABLE AS PART OF THE ECS
WILL BE CORRECT, ACCURATE, TIMELY OR OTHERWISE RELIABLE.**

8.2. USER UNDERSTANDS, AND ACCEPTS THAT (i) PG&E MAKES NO WARRANTY WHATSOEVER TO USER REGARDING THE ECS OR ITS AVAILABILITY OR THE RESULTS OF USER'S USE OF THE ECS, OR REGARDING ANY INFORMATION USED OR ACCESED IN CONNECTION THEREWITH; AND (ii) THE ECS IS PROVIDED BY PG&E ON AN "AS IS" BASIS AT USER'S SOLE RISK, AND PG&E EXPRESSLY DISCLAIMS ANY AND ALL WARRANTIES (WHETHER EXPRESS, IMPLIED, OR STATUTORY), INCLUDING THE WARRANTIES OF MERCHANTABILITY, NONINFRINGEMENT, FITNESS FOR A PARTICULAR PURPOSE AND SATISFACTORY QUALITY.

8.3. USER UNDERSTANDS AND AGREES THAT PG&E SHALL NOT BE LIABLE TO USER OR TO ANYONE BRINGING A CLAIM AS A RESULT OF OR IN CONNECTION WITH USER'S USE OF THE ECS (OR OF ANY SOFTWARE, INFORMATION OR OTHER ITEMS RELATING THERETO), FOR: (i) ANY LOSSES OR DAMAGES WHATSOEVER INCLUDING, BUT NOT LIMITED TO, DIRECT, INDIRECT, SPECIAL, COMPENSATORY, INCIDENTAL OR CONSEQUENTIAL DAMAGES INCLUDING, BUT NOT LIMITED TO, LOSS OF DATA, LOSS OF BUSINESS, REVENUE OR PROFITS OR FAILURE TO REALIZE SAVINGS OR ANY OTHER ECONOMIC OR COMMERCIAL LOSS OF ANY KIND, OR (ii) ANY CLAIM OR DAMAGES RESULTING FROM A CLAIM AGAINST THE USER BY ANY THIRD PARTY, ARISING IN ANY WAY IN CONNECTION WITH THIS AGREEMENT, OR USER'S USE OF THE ECS, WHETHER BASED IN CONTRACT, TORT (INCLUDING NEGLIGENCE), STRICT LIABILITY, WARRANTY OR OTHERWISE, AND WHETHER OR NOT SUCH DAMAGES ARE FORESEEABLE. THE TOTAL CUMULATIVE LIABILITY OF PG&E AND THIRD-PARTY SOFTWARE LICENSORS UNDER OR ARISING FROM THIS AGREEMENT, IF ANY, SHALL IN NO EVENT EXCEED AN AMOUNT EQUAL TO THE AVERAGE CHARGE PAID BY USER TO PG&E FOR A SINGLE DAY'S GAS TRANSPORTATION TRANSACTIONS DURING THE TWELVE (12) MONTHS PERIOD PRIOR TO THE DATE ON WHICH THE CAUSE OF ACTION AROSE, OR \$10,000 (TEN THOUSAND DOLLARS), WHICHEVER IS THE LESSER AMOUNT.

8.4 User shall hold harmless, protect, defend and indemnify PG&E from and against any and all claims, actions, demands, suits, judgments, damages, losses, costs, including attorneys' fees, and liabilities resulting from or arising out of or in connection with (i) use of or access to the ECS or to any software, information, data (or other items relating thereto) by User, or by any person obtaining access to the ECS through User or a User ID, whether or not User has authorized such access, or (ii) any breach by User of any terms or conditions of this Agreement, or

(iii) any act or omission, or willful misconduct, of User, its officers, agents or employees or any person obtaining access to the ECS through User (whether or not User has authorized such access) in the performance of this Agreement or the use of the ECS regardless of any negligence of PG&E, whether active or passive, or (iv) any actions taken or not taken by User based on its access to or use of the ECS.

8.5. As used in this Article 8, "PG&E" shall include the directors, officers, employees and agents of PG&E.

9. VIRUSES

Each party agrees to make reasonable efforts to notify the other promptly if there is any indication that its own computer systems, or any part thereof, have come into contact with any "computer virus." The term "computer virus" as used herein shall mean any computer software program or portion of a program that is foreign to the host computer system and has been introduced into the host computer system without the knowing consent of the operator of the ECS including without limitation a virus received over the Internet.

10. SYSTEM OR SOFTWARE MALFUNCTIONS

If User is notified or in any other way becomes aware of a malfunction, failure or stoppage of the ECS, related software, or the operation of either of these, User agrees to use conventional methods of communication, such as facsimile transmissions, to conduct the business for which the ECS is intended, for as long as the malfunction, failure or stoppage continues to exist.

11. MISCELLANEOUS PROVISIONS

11.1 Force Majeure: Neither PG&E nor User shall be considered in default in the performance of its obligations under this Agreement, except obligations to make payments hereunder when due, to the extent that the performance of any such obligation is prevented or delayed by any cause, existing or future, which is beyond the reasonable control of the affected party. For purposes of this Agreement, events beyond the reasonable control of a party shall include, but not be limited to, failures or malfunctions of the ECS or of any hardware or software used in connection therewith or furnished pursuant to this Agreement (including third-party software and software owned and/or operated by PG&E).

11.2. Assignment and Delegation: User acknowledges and agrees that PG&E has extended access to the ECS to User because of the specific business relationship between User and PG&E, and in some cases because of User's particular credit history. This Agreement may not be assigned by User without the prior written consent of PG&E.

11.3. Choice of Law: User agrees that the laws of the State of California, without giving effect to choice of law provisions, shall govern the interpretation and enforcement of this Agreement

11.4. Dispute Resolution: Any dispute arising under or related to this Agreement, which dispute cannot be settled by the parties within a reasonable time, may be submitted by either Party to binding arbitration in accordance with the rules of the American Arbitration Association. All disputes to be arbitrated shall be decided by one arbitrator to be appointed by the parties. If the parties fail to agree upon an arbitrator within thirty (30) days after written notice of arbitration has been given by either party to the other, the presiding judge of the Superior Court of the State of California and for the City and County of San Francisco shall appoint an arbitrator upon the request of either party. Venue for arbitration will be the City and County of San Francisco, California. The decision of the arbitrator shall be final and binding upon the parties hereto and judgment thereon may be entered in any court of competent jurisdiction. The cost of the arbitrator shall be borne equally by User and PG&E. Nothing contained in this paragraph 11.4 shall preclude either party from seeking equitable relief or remedies in a court of competent jurisdiction. In reaching a decision herein, arbitrator shall adhere to and apply substantive California law. User agrees that for any violation of any provision of this Agreement, a restraining order and/or injunction may be issued against User.

11.5. No Waiver: No waiver, by either PG&E or User, of any default by the other in the performance of any provision of this Agreement shall operate as a waiver of any continuing or future default, whether of a like or different character.

11.6. Notices: Except as otherwise required by law, all notices relating to this Agreement, including notices of arbitration and notifications pursuant to Article 4.1.1, shall be in writing and given by means of personal delivery, facsimile transmission, or mail (with return receipt requested). Any notice given as stated in this paragraph 11.6 shall be deemed duly given as follows: upon delivery, if delivered personally; upon transmission, if sent by facsimile; on the date of receipt, if sent by mail, return receipt requested. All notices shall be addressed, and sent to the addresses or facsimile numbers, as set forth below:

USER: PG&E:

PG&E Gas Transmission - Northwest Corp. Pacific Gas and Electric Company

2100 SW River Parkway
Portland, OR 97201
Attention: Jay Story

Fax No.: (503) 833-4396
Telephone No.: (503) 833-4309
Email Address: jay.story@neg.pge.com

Products & Sales
Mail Code N15A
P.O. Box 770000
San Francisco, CA 94177
Attention: Products and Sales

Fax No.: (415) 973-9247
Telephone No.: (415) 973-0474
Email Address: cgtpscontracts@pge.com

The parties may change their addresses, or any part thereof, by a notice pursuant to this Article 11.6.

12. CAPTIONS

All captions, titles, subject headings, and similar items are provided for the purpose of reference and convenience and are not intended to affect the meaning or interpretation of the content or scope of this Agreement.

13. ATTACHMENTS

The following attachments to this Agreement are incorporated herein by this reference: Exhibit A - "Third Party Software" and Exhibit B "Access Request Form."

14. EXECUTION

Each party represents that the individual executing this Agreement for such party has been duly authorized to do so.

PG&E Gas Transmission - Northwest Corp. Pacific Gas and Electric Company

By: JAY STORY

(Signature)

Name: Jay Story

Title: Director, Gas Control & Transp.
Srv.

Date of Signature: 9/18/01

By: DANIEL F. THOMAS

(Signature)

Name: Daniel F. Thomas

Title: Director, Products and Sales

Date of Signature: 9/28/01

Electronic Commerce System User Agreement

EXHIBIT A

Third-Party Software

The following third-party software packages will be downloaded upon each login in order to operate the ECS:

Vendor:	Citrix Systems, Inc.
Package:	Metaframe
Version:	1.8

Electronic Commerce System User Agreement

EXHIBIT B

Access Request Form

Company Name: PG&E Gas Transmission - Northwest Corporation

User requests access to the Electronic Commerce Systems (ECS) for the following designated individuals who are authorized by User to access and use the ECS and enter into binding contracts on behalf of User.

Name: Marvin Hoffman
Title: Transportation Coordinator
E-Mail Address: marvin.hoffman@neg.pge.com Telephone No. (503) 833-4319
Mother's maiden name (for phone verification): Jacobson User Code: _____ (PG&E Use)

Name: Sue Crannell
Title: Transportation Coordinator
E-Mail Address: sue.crannell@neg.pge.com Telephone No. (503) 833-4317
Mother's maiden name (for phone verification): Fricia User Code: _____ (PG&E Use)

Name: Brian Hart
Title: Transportation Coordinator
E-Mail Address: brian.hart@neg.pge.com Telephone No. (503) 833-4315
Mother's maiden name (for phone verification): Goldsmith User Code: _____ (PG&E Use)

Names: Emily Roberts
Title: Transportation Coordinator
E-Mail Address: emily.roberts@neg.pge.com Telephone No. (503) 833-4316
Mother's maiden name (for phone verification): Marggi User Code: _____ (PG&E Use)

Name: Ruth Clark

Title: Transportation Coordinator

E-Mail Address: ruth.clark@neg.pge.com Telephone No. (503) 833-4314

Mother's maiden name (for phone verification): Goulet User Code: _____(PG&E Use)

EXHIBIT 10.24

2004 SHORT-TERM INCENTIVE PLAN

BACKGROUND

At its meeting on December 17, 2003, the Nominating and Compensation Committee reviewed and approved the 2004 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.

ATTACHMENT A

2004 RECOMMENDED OFFICER SHORT-TERM INCENTIVE PLAN STRUCTURE

OFFICER GROUP	AWARD COMPONENT	WEIGHT	PERFORMANCE MEASURES
PG&E Corporation	Corporate Financial Performance	75%	Corporate earnings from operations
	Utility Plan of Reorganization	25%	Progress towards the reorganization of Pacific Gas and Electric Company
Pacific Gas and Electric Company - Senior Officers (Officer Bands 2-4)	Corporate Financial Performance	25%	Corporate earnings from operations
	Subsidiary Financial Performance	50%	Subsidiary contribution to corporate earnings from operations
	Utility Plan of Reorganization	25%	Progress towards the reorganization of Pacific Gas and Electric Company
Pacific Gas and Electric Company - Officers (Officer Bands 5-6)	Corporate Financial Performance	25%	Corporate earnings from operations
	Subsidiary Financial Performance	25%	Subsidiary contribution to corporate earnings from operations
	Utility Plan of Reorganization	25%	Progress towards the reorganization of Pacific Gas and Electric Company
	Subsidiary Operational Performance	25%	Financial, operating, and service measures determined by subsidiary CEO

EXHIBIT 10.37

**PG&E CORPORATION
LONG-TERM INCENTIVE PROGRAM**

RESTRICTED STOCK AGREEMENT

PG&E CORPORATION, a California corporation, hereby grants shares of Restricted Stock to the Recipient named below. The shares of Restricted Stock have been awarded under the PG&E Corporation Long-Term Incentive Program (the "LTIP"). The terms and conditions of the Restricted Stock are set forth in this cover sheet and in the attached Restricted Stock Award Agreement (the "Agreement").

Date of Award: January 2, 2004

Name of Recipient: _____

Recipient's Social Security Number: ____ - ____ - ____

Number of Shares of Restricted Stock Awarded: _____

Aggregate Fair Market Value of Restricted Stock on Date of Award: \$ _____

BY SIGNING THIS COVER SHEET, YOU AGREE TO ALL OF THE TERMS AND CONDITIONS DESCRIBED IN THE ATTACHED AGREEMENT. YOU AND PG&E CORPORATION AGREE TO EXECUTE SUCH FURTHER INSTRUMENTS AND TO TAKE SUCH FURTHER ACTION AS MAY REASONABLY BE NECESSARY TO CARRY OUT THE INTENT OF THE ATTACHED AGREEMENT. YOU ARE ALSO ACKNOWLEDGING RECEIPT OF THIS AGREEMENT AND A COPY OF THE PROSPECTUS DESCRIBING THE LTIP AND THE RESTRICTED STOCK DATED JANUARY 1, 2004.

Recipient: _____

(Signature)

Attachment

Please return your signed Agreement to PG&E Corporation, Human Resources, One Market Street, Spear Street Tower, Suite 400, San Francisco, California

**PG&E CORPORATION
LONG-TERM INCENTIVE PROGRAM**

RESTRICTED STOCK AGREEMENT

**THE LTIP AND
OTHER
AGREEMENTS**

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock, subject to the terms of the LTIP. Any prior agreements, commitments or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern.

**GRANT OF
RESTRICTED STOCK**

PG&E Corporation grants you the number of shares of Restricted Stock shown on the cover sheet of this Agreement. The shares of Restricted Stock are subject to the terms and conditions of this Agreement and the LTIP.

**LAPSE OF
RESTRICTIONS**

As long as you remain employed with PG&E Corporation (or any of its subsidiaries), the restrictions will lapse as to 25 percent of the total number of shares of Restricted Stock originally subject to this Agreement, as shown above on the cover sheet, on the first business day of January of each of the first, second, third and fourth years following the Date of Award (each such day an "Annual Lapse Date"). Except as described below, all shares of Restricted Stock subject to this Agreement as to which the restrictions have not lapsed shall be forfeited upon termination of your employment.

**VOLUNTARY
TERMINATION**

In the event that you terminate your employment with PG&E Corporation voluntarily, you will automatically forfeit to PG&E Corporation all of the shares of Restricted Stock as to which the restrictions have not lapsed subject to this Agreement as of the date of such Termination.

**TERMINATION FOR
CAUSE**

If your employment with PG&E Corporation (or any of its subsidiaries) is terminated by PG&E Corporation or the subsidiary for cause, you will automatically forfeit to PG&E Corporation all shares of Restricted Stock as to which the restrictions have not lapsed subject to this Agreement as of the date of such termination. In general, termination for "cause" means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation or the employing subsidiary.

TERMINATION
OTHER THAN FOR
CAUSE

If your employment with PG&E Corporation (or any of its subsidiaries) is terminated by PG&E Corporation or the subsidiary other than for cause before the restrictions on your Restricted Stock lapse, and you are an officer in Bands 1-5, the restrictions on your outstanding shares of Restricted Stock that would have lapsed during the period of the "Severance Multiple" under the applicable severance policy shall continue to lapse pursuant to the regular lapse schedule (or sooner, in the event of a Change in Control during such period). In the event of your involuntary termination other than for cause, if you are not an officer in Bands 1-5, the restrictions on your outstanding shares of Restricted Stock that would have lapsed within 12 months following such termination will continue to lapse pursuant to the regular lapse schedule (or sooner, in the event of a Change in Control during such period). All other outstanding shares of Restricted Stock shall automatically be forfeited to PG&E Corporation upon such termination.

RETIREMENT

In the event of your Retirement, the restrictions on your outstanding shares of Restricted Stock will continue to lapse as though your employment had continued. You will be considered to have retired if you are age 55 or older on the date of termination and if you were employed by PG&E Corporation or any of its subsidiaries for at least five consecutive years ending on the date of termination of your employment.

DEATH/DISABILITY

If your employment terminates due to your death or disability, the restrictions on all of your shares of Restricted Stock shall lapse on the next Annual Lapse Date. In the event of a Change in Control of PG&E Corporation after such termination and before such next Annual Lapse Date, the restrictions as to all shares of Restricted Stock shall immediately lapse as described below under "Change in Control."

TERMINATION
DUE TO
DISPOSITION OF
SUBSIDIARY

If (1) your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Code or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, the restrictions on all shares of Restricted Stock shall lapse on the next Annual Lapse Date. In the event of a Change in Control of PG&E Corporation after such Termination and before such next Annual Lapse Date, the restrictions as to all shares of Restricted Stock shall immediately lapse as described below under "Change in Control."

ESCROW

The certificates for the Restricted Stock shall be deposited in escrow with the Corporate Secretary of PG&E Corporation to be held in accordance with the provisions of this paragraph. Each deposited certificate shall be accompanied by any assignment documents PG&E Corporation may require you to execute. The deposited certificates shall remain in escrow until such time as the certificates are to be released or otherwise surrendered for cancellation as discussed below. Upon delivery of the certificates to PG&E Corporation, you shall be issued an instrument of deposit acknowledging the number of shares of Restricted Stock delivered in escrow to the Corporate Secretary of PG&E Corporation.

All dividends, if any, on the Restricted Stock shall be held in escrow and subject to the same restrictions as the shares to which they relate.

RELEASE OF SHARES AND WITHHOLDING TAXES

The shares of Restricted Stock held in escrow hereunder shall be subject to the following terms and conditions relating to their release from escrow or their surrender to PG&E Corporation:

- When the restrictions as to your shares of Restricted Stock lapse as described above, the certificates for such shares shall be released from escrow and delivered to you, at your request within thirty (30) days of the applicable Annual Lapse Date.
- Upon your Termination, any shares of Restricted Stock as to which the restrictions have not lapsed shall be forfeited and automatically surrendered to PG&E Corporation as provided herein.

Note that you must make arrangements acceptable to PG&E Corporation to satisfy withholding or other taxes that may be due before your shares will be released to you. If you so elect, PG&E Corporation will assist you in selling your shares through a broker so that you can use the sales proceeds to satisfy applicable taxes. You will receive the remaining proceeds in cash. However, if you wish to receive the stock certificates in lieu of selling your shares, you will need to make arrangements to pay the applicable taxes either by check or through payroll deduction. PG&E Corporation will notify you about how to instruct PG&E Corporation to sell your shares when the restrictions lapse or make other arrangements.

CHANGE IN CONTROL

The restrictions on all of your outstanding shares of Restricted Stock shall automatically lapse and become nonforfeitable in the event there is a Change in Control of PG&E Corporation.

CODE SECTION
83(b) ELECTION

Under Section 83(a) of the Internal Revenue Code of 1986, as amended (the "Code"), the Fair Market Value of the Restricted Stock on the date any forfeiture restrictions applicable to such Restricted Stock lapse will be reportable as ordinary income at that time. For this purpose, "forfeiture restrictions" include surrender to PG&E Corporation of Restricted Stock as described above. You may elect to be taxed at the time the Restricted Stock is awarded to you, rather than when the restrictions lapse by filing an election under Section 83(b) of the Code with the Internal Revenue Service within thirty (30) days after the Date of Award. The form for making this election is attached as Exhibit A hereto. Failure to make this filing within the thirty (30) day period will result in the recognition of ordinary income by you (in the event the Fair Market Value of the Restricted Stock increases after the date of purchase) as the forfeiture restrictions lapse. YOU ACKNOWLEDGE THAT IT IS YOUR SOLE RESPONSIBILITY, AND NOT PG&E CORPORATION'S, TO FILE A TIMELY ELECTION UNDER CODE SECTION 83(b). YOU ARE RELYING SOLELY ON YOUR OWN ADVISORS WITH RESPECT TO THE DECISION AS TO WHETHER OR NOT TO FILE A CODE SECTION 83(b) ELECTION.

LEAVES OF
ABSENCE

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation (or any of its subsidiaries), or a recipient of Company sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under "Voluntary Termination."

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

VOTING AND
OTHER RIGHTS

Subject to the terms of this Agreement, you shall have all the rights and privileges of a shareholder of PG&E Corporation while the Restricted Stock is held in escrow, including the right to vote. As described above, all dividends, if any, on the Restricted Stock shall be held in escrow and subject to the same restrictions as the shares to which they relate.

RESTRICTIONS ON
ISSUANCE

PG&E Corporation will not issue any Restricted Stock if the issuance of such Restricted Stock at that time would violate any law or regulation.

RESTRICTIONS ON
RESALE AND
HEDGE
TRANSACTIONS

By signing this Agreement, you agree not to sell any Restricted Stock before the restrictions lapse or sell any shares acquired under this award at a time when applicable laws, regulations or Company or underwriter trading policies prohibit sale. In particular, in connection with any underwritten public offering by PG&E Corporation of its equity securities pursuant to an effective registration statement filed under the Securities Act of 1933, you shall not sell, make any short sale of, loan, hypothecate, pledge, grant any option for the purchase of, or otherwise dispose or transfer for value or agree to engage in any of the foregoing transactions with respect to any shares acquired under this award without the prior written consent of PG&E Corporation or its underwriters, for such period of time after the effective date of such registration statement as may be requested by PG&E Corporation or the underwriters.

If the sale of shares acquired under this award is not registered under the Securities Act of 1933, but an exemption is available which requires an investment or other representation and warranty, you shall represent and agree that the Shares being acquired are being acquired for investment, and not with a view to the sale or distribution thereof, and shall make such other representations and warranties as are deemed necessary or appropriate by PG&E Corporation and its counsel.

By your acceptance of the award, you agree that while the Restricted Stock is subject to restrictions, you will not enter into a corresponding hedging transaction relating to PG&E Corporation's stock nor engage in any short sale of PG&E Corporation's stock. This prohibition shall not apply to transactions effected through PG&E Corporation's benefit plans that provide an opportunity to invest in Company stock or which provide compensation based on the price of Company stock.

NO RETENTION
RIGHTS

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation (or its subsidiaries). Except as otherwise provided in an applicable employment agreement, the Company (or any of its subsidiaries) reserves the right to terminate your employment at any time and for any reason.

LEGENDS

All certificates representing the Restricted Stock issued under this award shall, where applicable, have endorsed thereon the following legends:

"THE SHARES REPRESENTED BY THIS CERTIFICATE ARE SUBJECT TO CERTAIN RESTRICTIONS ON TRANSFER SET FORTH IN AN AGREEMENT BETWEEN PG&E CORPORATION AND THE REGISTERED HOLDER, OR HIS OR HER PREDECESSOR IN INTEREST. A COPY OF SUCH AGREEMENT IS ON FILE AT THE PRINCIPAL OFFICE OF PG&E

CORPORATION AND WILL BE FURNISHED UPON WRITTEN
REQUEST TO THE CORPORATE SECRETARY OF PG&E
CORPORATION BY THE HOLDER OF RECORD OF THE SHARES
REPRESENTED BY THIS CERTIFICATE."

Applicable Law

This Agreement will be interpreted and enforced under
the laws of the State of California.

**BY SIGNING THE COVER SHEET OF THIS AGREEMENT, YOU AGREE TO ALL OF THE TERMS AND CONDITIONS
DESCRIBED ABOVE AND IN THE LTIP.**

Note: Do not have this Section 83(b) Election filed unless you wish to pay tax withholding to PG&E Corporation at the same time.

EXHIBIT A

**ELECTION UNDER SECTION 83(b) OF
THE INTERNAL REVENUE CODE**

The undersigned hereby makes an election pursuant to Section 83(b) of the Internal Revenue Code with respect to the property described below and supplies the following information in accordance with the regulations promulgated thereunder:

1. The name, address and social security number of the undersigned:

Social Security No.: _____

2. Description of property with respect to which the election is being made:

_____ shares of common stock of PG&E Corporation.

3. The date on which the property was transferred is January 2, 2004.

4. The taxable year to which this election relates is calendar year 2004.

5. Nature of restrictions to which the property is subject:

The shares of stock are subject to the provisions of a Restricted Stock Award Agreement (the "Agreement") between the undersigned and PG&E Corporation. The shares of stock are subject to forfeiture under the terms of the Agreement.

6. The fair market value of the property at the time of transfer (determined without regard to any lapse restriction) was \$_____ per share, for a total of \$_____.

7. The amount paid by taxpayer for the property was \$ 0 .

8. A copy of this statement has been furnished to PG&E Corporation.

Dated: _____, 2004

[Taxpayer's Name]

Note: A valid Section 83(b) Election must be filed with the IRS within 30 days of the Date of Award. Accordingly, if you wish to file, please submit this signed form for receipt by January 29, 2003 to PG&E Corporation, Human Resources, One Market Street, Spear Street Tower, Suite 400, San Francisco, CA 94105.

EXHIBIT 10.38

**PG&E CORPORATION
LONG-TERM INCENTIVE PROGRAM**

PERFORMANCE SHARE AGREEMENT

PG&E CORPORATION, a California corporation, hereby grants Performance Shares to the Recipient named below. The Performance Shares have been awarded under the PG&E Corporation Long-Term Incentive Program (the "LTIP"). The terms and conditions of the Performance Shares are set forth in this cover sheet and the attached Performance Share Agreement (the "Agreement").

Date of Grant: January 2, 2004

Name of Recipient: _____

Recipient's Social Security Number: ____ - ____ - ____

Number of Performance Shares: _____

BY SIGNING THIS COVER SHEET, YOU AGREE TO ALL OF THE TERMS AND CONDITIONS DESCRIBED IN THE ATTACHED AGREEMENT. YOU AND PG&E CORPORATION AGREE TO EXECUTE SUCH FURTHER INSTRUMENTS AND TO TAKE SUCH FURTHER ACTION AS MAY REASONABLY BE NECESSARY TO CARRY OUT THE INTENT OF THIS AGREEMENT. YOU ARE ALSO ACKNOWLEDGING RECEIPT OF THIS AGREEMENT AND A COPY OF THE PROSPECTUS DESCRIBING THE LTIP AND THE PERFORMANCE SHARES DATED JANUARY 1, 2004.

Recipient: _____

(Signature)

Attachment

Please return your signed Agreement to PG&E Corporation, Human Resources, One Market Street, Spear Street Tower, Suite 400, San Francisco, California

94105

**PG&E CORPORATION
LONG-TERM INCENTIVE PROGRAM**

PERFORMANCE SHARE AGREEMENT

**THE LTIP AND
OTHER
AGREEMENTS**

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Performance Shares, subject to the terms of the LTIP. Any prior agreements, commitments or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern.

**GRANT OF
PERFORMANCE
SHARES**

PG&E Corporation grants you the number of Performance Shares shown on the cover sheet of this Agreement. The Performance Shares are subject to the terms and conditions of this Agreement and the LTIP.

**VESTING OF
PERFORMANCE
SHARES**

As long as you remain employed with PG&E Corporation (or any of its subsidiaries), the Performance Shares will vest on the first business day of January (the "Vesting Date") of the third year following the date of grant specified in the cover sheet. Except as described below, all Performance Shares subject to this Agreement that have not vested shall be forfeited upon termination of your employment.

**PAYMENT OF
PERFORMANCE
SHARES**

Upon the Vesting Date, PG&E Corporation's total shareholder return (TSR) will be compared to the TSR of the fifteen other companies in PG&E Corporation's comparator group⁽¹⁾ for the prior three calendar years (the "Performance Period"). Subject to rounding considerations, there will be no payout for TSR below the 25th percentile of the comparator group; TSR at the 25th percentile will result in a 25% payout of Performance Shares; TSR at the 75th percentile will result in a 100% payout of Performance Shares; and TSR at the 90th percentile or greater will result in a 200% payout of Performance Shares. The payment will equal the product of the number of vested Performance Shares, the payout percentage, and the average price of a share of PG&E Corporation common stock for the last 30 calendar days of the year preceding the Vesting Date. Payments will be made in January of the year in which the Vesting Date occurs.

**VOLUNTARY
TERMINATION**

If you terminate your employment with PG&E Corporation (or any of its subsidiaries) voluntarily before the Vesting Date, all of the Performance Shares shall be cancelled as of the date of such termination.

(1) The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

TERMINATION FOR
CAUSE

If your employment with PG&E Corporation (or any of its subsidiaries) is terminated by PG&E Corporation or the subsidiary for cause before the Vesting Date, all of the Performance Shares shall be cancelled as of the date of such termination. In general, termination for "cause" means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation or the employing subsidiary.

TERMINATION
OTHER THAN FOR
CAUSE

If your employment with PG&E Corporation (or any of its subsidiaries) is terminated by PG&E Corporation or the subsidiary other than for cause before the Vesting Date, your unvested Performance Shares will vest proportionally based on your service to the date of termination and will be payable, if at all, in January of the year in which the Vesting Date occurs. The formula for proportional vesting is as follows: time worked to termination (number of months rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares shall automatically be cancelled upon such termination.

RETIREMENT

If you retire before the Vesting Date, your outstanding Performance Shares will continue to vest as though your employment had continued and will be payable, if at all, in January of the year in which the Vesting Date occurs. You will be considered to have retired if you are age 55 or older on the date of termination and if you were employed by PG&E Corporation or any of its subsidiaries for at least five consecutive years ending on the date of termination of your employment.

DEATH/DISABILITY

If your employment terminates due to your death or disability before the Vesting Date, all of your Performance Shares shall vest and will be payable, if at all, on the Vesting Date.

TERMINATION DUE
TO DISPOSITION OF
SUBSIDIARY

If (1) your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Code or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, all Performance Shares shall vest proportionally based on service to the date of termination and will be payable, if at all in January of the year in which the Vesting Date occurs. The formula for proportional vesting is as follows: time worked to termination (number of months rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares shall automatically be cancelled upon such Termination.

WITHHOLDING
TAXES

PG&E Corporation will withhold amounts necessary to satisfy applicable taxes from the payment to be made with respect to your Performance Shares. You will receive the remaining proceeds in cash.

CHANGE IN
CONTROL

All of your outstanding Performance Shares shall automatically vest, and become nonforfeitable if there is a Change in Control of PG&E Corporation before the Vesting Date. Such vested shares will become payable on the first business day of the year following the Change in Control. The payment, if any, will be based on PG&E Corporation's TSR for the period from the date of grant to the date of the Change in Control compared to the TSR of the other companies in PG&E Corporation's comparator group(2) for the same period. There will be no payout for TSR below the 25th percentile of the comparator group; TSR at the 25th percentile will result in a 25% payout of Performance Shares; TSR at the 75th percentile will result in a 100% payout of Performance Shares; and TSR at the 90th percentile or greater will result in a 200% payout of Performance Shares. The payment will equal the product of the number of vested Performance Shares, the payout percentage, and the average price of a share of PG&E Corporation common stock for the last 30 calendar days preceding the Change in Control.

LEAVES OF
ABSENCE

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation (or any of its subsidiaries), or a recipient of PG&E Corporation (or any of its subsidiaries) sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation (or any of its subsidiaries) sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under "Voluntary Termination."

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

NO RETENTION
RIGHTS

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation (or its subsidiaries). Except as otherwise provided in an applicable employment agreement, the Company (or any of its subsidiaries) reserves the right to terminate your employment at any time and for any reason.

APPLICABLE LAW

This Agreement will be interpreted and enforced under the laws of the State of California.

BY SIGNING THE COVER SHEET OF THIS AGREEMENT, YOU AGREE TO ALL OF THE TERMS AND CONDITIONS DESCRIBED ABOVE AND IN THE LTIP.

(2) The identities of the companies currently comprising the comparator group are included in the prospectus. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

EXHIBIT 11

PG&E CORPORATION

COMPUTATION OF EARNINGS PER COMMON SHARE

(in millions, except per share amounts)	YEAR ENDED DECEMBER 31,		
	2003	2002 (1)	2001 (1)
Income from continuing operations	\$ 791	\$ 1,723	\$ 1,021
Discontinued operations	(365)	(2,536)	69
Net income (loss) before cumulative effect of changes in accounting principles	426	(813)	1,090
Cumulative effect of changes in accounting principles	(6)	(61)	9
NET INCOME (LOSS)	420	(874)	1,099
Add income impact of assumed conversions:			
Interest expense on 9.5% Convertible Subordinated Notes, net of tax	17	8	-
NET INCOME (LOSS) FOR DILUTED CALCULATIONS	\$ 437	\$ (866)	\$ 1,099
WEIGHTED AVERAGE COMMON SHARES OUTSTANDING, BASIC (2)	385	371	363
Add incremental shares from assumed conversions:			
Employee Stock Options, Restricted Stocks and PG&E Corporation shares held by grantor trusts	4	2	1
PG&E Corporation Warrants	5	2	-
9.5% Convertible Subordinated Notes	19	9	-
SHARES OUTSTANDING FOR DILUTED CALCULATIONS	413	384	364
EARNINGS (LOSS) PER COMMON SHARE, BASIC			
Income from continuing operations	\$ 2.05	\$ 4.64	\$ 2.81
Discontinued operations	(0.94)	(6.84)	0.19
Cumulative effect of changes in accounting principles	(0.02)	(0.16)	0.02
Rounding	-	-	0.01
NET EARNINGS (LOSS)	\$ 1.09	\$ (2.36)	\$ 3.03
EARNINGS (LOSS) PER COMMON SHARE, DILUTED			
Income from continuing operations	\$ 1.96	\$ 4.50	\$ 2.80
Discontinued operations	(0.88)	(6.60)	0.19
Cumulative effect of changes in accounting principles	(0.02)	(0.16)	0.02
Rounding	-	-	0.01
NET EARNINGS (LOSS)	\$ 1.06	\$ (2.26)	\$ 3.02

PG&E Corporation reflects the preferred dividends of its subsidiary as other expense for computation of both basic and diluted earnings per share.

(1) Prior period amounts of NEGТ have been reclassified as discontinued operations.

(2) Weighted average common shares outstanding exclude shares held by a subsidiary of PG&E Corporation (23,815,500 shares at December 31, 2003, 2002 and 2001) and PG&E Corporation shares held by grantor trusts to secure deferred compensation obligations (281,985 shares at December 31, 2003, 2002 and 2001).

EXHIBIT 12.1

**PACIFIC GAS AND ELECTRIC COMPANY
A DEBTOR-IN-POSSESSION
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

(in millions)	YEAR ENDED DECEMBER 31,				
	2003	2002	2001	2000	1999
	----	----	----	----	----
EARNINGS:					
Net income (loss)	\$ 923	\$ 1,819	\$ 1,015	\$(3,483)	\$ 788
Income taxes provision (benefit)	528	1,178	596	(2,154)	648
Net fixed charges	964	1,029	1,019	648	637
	-----	-----	-----	-----	-----
TOTAL EARNINGS (LOSS)	\$ 2,415	\$ 4,026	\$ 2,630	\$(4,989)	\$ 2,073
	=====	=====	=====	=====	=====
FIXED CHARGES:					
Interest on short-term borrowings					
and long-term debt, net	\$ 947	\$ 996	\$ 981	\$ 616	\$ 604
Interest on capital leases	1	2	2	2	3
AFUDC debt	16	21	12	6	7
Earnings required to cover the					
preferred stock dividend and					
preferred security distribution					
requirements of majority owned					
trust	--	10	24	24	24
	-----	-----	-----	-----	-----
TOTAL FIXED CHARGES	\$ 964	\$ 1,029	\$ 1,019	\$ 648	\$ 638
	=====	=====	=====	=====	=====
RATIOS OF EARNINGS (LOSS) TO					
FIXED CHARGES	2.51	3.91	2.58	(7.70)(1)	3.25
	=====	=====	=====	=====	=====

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, cash distributions from and equity in undistributed income or loss of Pacific Gas and Electric Company's 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 of subordinated debentures held by trust, interest on capital leases, 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 12.2

PACIFIC GAS AND ELECTRIC COMPANY A DEBTOR-IN-POSSESSION COMPUTATION OF RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

(in millions)	YEAR ENDED DECEMBER 31,				
	2003	2002	2001	2000	1999
	----	----	----	----	----
EARNINGS:					
Net income (loss)	\$ 923	\$ 1,819	\$ 1,015	\$(3,483)	\$ 788
Income taxes provision (benefit)	528	1,178	596	(2,154)	648
Net fixed charges	964	1,029	1,019	648	637
	-----	-----	-----	-----	-----
TOTAL EARNINGS (LOSS)	\$ 2,415	\$ 4,026	\$ 2,630	\$(4,989)	\$ 2,073
	=====	=====	=====	=====	=====
FIXED CHARGES:					
Interest on short-term borrowings and long-term debt, net	\$ 947	\$ 996	\$ 981	\$ 616	\$ 604
Interest on capital leases	1	2	2	2	3
AFUDC debt	16	21	12	6	7
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	--	10	24	24	24
	-----	-----	-----	-----	-----
TOTAL FIXED CHARGES	964	1,029	1,019	648	638
	-----	-----	-----	-----	-----
PREFERRED STOCK DIVIDENDS:					
Tax deductible dividends	9	9	9	9	9
Pretax earnings required to cover non-tax deductible preferred stock dividend requirements	27	28	27	27	27
	-----	-----	-----	-----	-----
TOTAL PREFERRED STOCK DIVIDENDS	36	37	36	36	36
	-----	-----	-----	-----	-----
TOTAL COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS	\$ 1,000	\$ 1,066	\$ 1,055	\$ 684	\$ 674
	=====	=====	=====	=====	=====
RATIOS OF EARNINGS (LOSS) TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS					
	2.42	3.78	2.49	(7.29)(1)	3.08
	=====	=====	=====	=====	=====

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, cash distributions from and equity in undistributed income or loss of Pacific Gas and Electric Company's 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, interest of subordinated debentures held by trust, and earnings required to cover the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust. "Preferred stock dividends" represent pretax earnings that are required to pay the 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.

SELECTED FINANCIAL DATA

	2003	2002	2001	2000	1999
(in millions, except per share amounts)					
PG&E Corporation ⁽¹⁾					
For the Year					
Operating revenues	\$10,435	\$10,505	\$10,450	\$ 9,623	\$ 9,084
Operating income (loss)	2,343	3,954	2,613	(5,077)	1,950
Income (loss) from continuing operations	791	1,723	1,021	(3,435)	713
Earnings (loss) per common share from continuing operations, basic	2.05	4.64	2.81	(9.49)	1.94
Earnings (loss) per common share from continuing operations, diluted	1.96	4.50	2.80	(9.49)	1.93
Dividends declared per common share	—	—	—	1.20	1.20
At Year-End					
Book value per common share	\$ 10.75	\$ 9.47	\$ 11.91	\$ 8.76	\$ 19.13
Common stock price per share	27.77	13.90	19.24	20.00	20.50
Total assets	30,175	33,060	35,693	36,152	29,588
Long-term debt (excluding current portion)	3,314	3,715	3,923	3,346	4,877
Rate reduction bonds (excluding current portion)	870	1,160	1,450	1,740	2,031
Financial debt subject to compromise	5,603	5,605	5,651	—	—
Redeemable preferred stock and securities of subsidiaries (excluding current portion)	286	286	586	586	586
Pacific Gas and Electric Company ⁽¹⁾					
For the Year					
Operating revenues	\$10,438	\$10,514	\$10,462	\$ 9,637	\$ 9,228
Operating income (loss)	2,339	3,913	2,478	(5,201)	1,993
Income available for (loss allocated to) common stock	901	1,794	990	(3,508)	763
At Year-End					
Total assets	\$29,066	\$24,572	\$25,269	\$21,988	\$21,470
Long-term debt (excluding current portion)	2,431	2,739	3,019	3,342	4,877
Rate reduction bonds (excluding current portion)	870	1,160	1,450	1,740	2,031
Financial debt subject to compromise	5,603	5,605	5,651	—	—
Redeemable preferred stock and securities (excluding current portion)	286	286	586	586	586

- (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. See Management's Discussion and Analysis of Financial Condition and Results of Operations and Notes to the Consolidated Financial Statements for discussion of matters relating to certain data.

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, electricity transmission, and natural gas 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. PG&E Corporation also owns National Energy & Gas Transmission, Inc., or NEGT, formerly known as PG&E National Energy Group, Inc., which engages 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 3.9 million natural gas distribution customers at December 31, 2003. The Utility had approximately \$29.1 billion in assets at December 31, 2003 and generated revenues of approximately \$10.4 billion in 2003. 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.

Restructuring of the California Electricity Industry

In 1996, California enacted Assembly Bill, or 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. As required by AB 1890, beginning January 1, 1997, electricity rates for all customers were frozen at the level in effect on June 10, 1996 and, beginning January 1, 1998, rates for residential customers were further reduced by 10%. The frozen rates were designed to allow the Utility to recover its authorized utility costs and, to the extent the frozen rates generated revenues greater than these costs, to recover the Utility's costs stranded by the regulatory change, or transition costs.

AB 1890 also gave customers the choice of continuing to buy electricity from the California investor-owned electric utilities or, beginning in April 1998, purchasing electricity from an alternate energy provider. The customers that opted to purchase electricity from alternate energy service providers are known as direct access customers. The Utility bills direct access customers based on fully bundled rates that include electricity procurement, generation, distribution, transmission and other components. The Utility then gives direct access customers energy credits equal to the procurement component of the fully bundled rates, or direct access credits.

The California Energy Crisis and the Utility's Chapter 11 Proceeding

Beginning in May 2000, wholesale electricity prices began to increase so that the frozen rates were not sufficient to recover the Utility's operating and electricity procurement costs. The Utility financed the higher costs of wholesale electricity by issuing debt in the fall of 2000 and drawing on its credit facilities. Ultimately, the inability of the Utility to recover its electricity procurement costs from its customers resulted in billions of dollars in defaulted debt and unpaid bills. 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. The Utility retained control of its assets and is authorized to operate its business as a debtor-in-possession during its Chapter 11 proceeding.

In January 2001, because of the deteriorating credit of the California investor-owned electric utilities, the State of California Department of Water Resources, or DWR, began purchasing electricity to meet each 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 is legally and financially responsible for its electricity 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. These customers also must pay another revenue requirement, which is known as a bond charge, for the DWR's costs associated with its \$11.3 billion bond offering completed in November 2002. On January 1, 2003, each California investor-owned electric utility resumed purchasing electricity to meet the portion of its net open position not provided by the DWR contracts allocated to that utility's customers, or that utility's residual net open position.

In January 2001, the CPUC authorized the Utility to collect the first of three electricity surcharges intended to help it reduce the impact of the high wholesale electricity prices. The rate surcharges totaled \$0.045 per kilowatt-hour, or kWh, and were fully implemented by June 2001.

In mid-2001, wholesale electricity prices moderated. As a result of these surcharges and moderating electricity prices, the Utility's net income and cash balances increased. This has allowed the Utility to pay its post-petition operating expenses and other post-petition liabilities with internally generated funds. In addition, the Utility has paid interest on certain pre-petition liabilities and the principal of maturing mortgage bonds with bankruptcy court approval.

The Utility's Plan of Reorganization and Settlement Agreement

In September 2001, PG&E Corporation and the Utility proposed a plan of reorganization that would have disaggregated the Utility's businesses. In April 2002, the CPUC, later joined by the Official Committee of Unsecured Creditors, proposed an alternate plan of reorganization that would not have disaggregated the Utility's businesses. On December 19, 2003, the CPUC, PG&E Corporation and the Utility entered into a settlement agreement, or the Settlement Agreement, that contemplated a new plan of reorganization, or the Plan of Reorganization, to supersede the competing plans. Under the Settlement Agreement, the Utility remains vertically integrated. On December 22, 2003, the bankruptcy court confirmed the Plan of Reorganization, which fully incorporates the Settlement Agreement. The Plan of Reorganization provides that the Utility will pay all allowed creditor claims in full (except for the claims of holders of certain pollution control-related bond obligations that will be reinstated) from the proceeds of a public offering of long-term debt, cash on hand and draws on credit facilities. At December 31, 2003, allowed claims in the Utility's Chapter 11 proceeding amounted to approximately \$12.2 billion.

The Settlement Agreement permits the Utility to emerge from Chapter 11 as an investment grade entity by generally ensuring that the Utility will have the opportunity to collect in rates reasonable costs of providing its utility service. The Settlement Agreement provides that the Utility's authorized return on equity will be no less than 11.22% per year and, except for 2004 and 2005, its authorized equity ratio will be no less than 52% until the Utility's credit rating has increased to a specified level. The Settlement Agreement establishes a \$2.21 billion after-tax regulatory asset and allows for the recognition of an approximately \$800 million after-tax regulatory asset related to generation assets. The Settlement Agreement and related decisions by the CPUC provide that the Utility's revenue requirement will be collected regardless of sales levels and that the Utility's rates will be timely adjusted to accommodate changes in costs that the Utility incurs.

On January 20, 2004, several parties filed applications with the CPUC requesting that the CPUC rehear and reconsider its decision approving the Settlement Agreement. Although the CPUC is not required to act on these applications within a specific time period, if the CPUC has not acted on an application within 60 days, that application may be deemed denied for purposes of seeking judicial review. In addition, the two CPUC Commissioners who did not vote to approve the Settlement Agreement and a municipality have appealed the bankruptcy court's confirmation order in the U.S. District Court for the Northern District of California, or the District Court. On January 5, 2004, the bankruptcy court denied a request to stay the implementation of the Plan of Reorganization until the appeals are resolved. The District Court will set a schedule for briefing and argument of the appeals at a later date. No additional parties may request rehearings or make appeals of the CPUC's approval of the Settlement Agreement or the bankruptcy court's confirmation order.

Implementation of the Plan of Reorganization is subject to various conditions, including the consummation of the public offering of long-term debt, the receipt of investment grade credit ratings and final CPUC approval of the Settlement Agreement. For purposes of these conditions, final approval means approval on behalf of the CPUC that is not subject to any pending appeal or further right of appeal, or approval on behalf of the CPUC that, although subject to a pending appeal or further right of appeal, has been agreed by the Utility and PG&E Corporation to constitute final approval. Thus, the terms of the Plan of Reorganization permit the Utility and PG&E Corporation to cause the Plan of Reorganization to become effective (and permit the Utility to issue the debt securities provided for under the Plan of Reorganization) while the CPUC's approvals are subject to pending appeals or further rights of appeal. Until certain conditions or events regarding the effectiveness of the Plan of Reorganization discussed above are resolved further, PG&E Corporation and the Utility do not believe that the applicable accounting probability standard needed to record the regulatory assets contemplated by the Settlement Agreement has been met. PG&E Corporation and the Utility believe that the Utility and the long-term debt to be issued will receive investment grade credit ratings. The Utility has targeted April 2004 to complete the sale of the long-term debt, which the Utility expects to be the last condition of the Plan of Reorganization to be satisfied. The Plan of Reorganization provides that the effective date will occur 11 business days after all the conditions have been satisfied or, with respect to all conditions except those relating to investment grade credit ratings, waived by PG&E Corporation and the Utility. There can be no assurance

that the Settlement Agreement will not be modified on rehearing or appeal or that the Plan of Reorganization will become effective.

2004 Rate Reduction

In early January 2004, the CPUC issued a decision finding that the rate freeze mandated by AB 1890 ended on January 18, 2001. In mid-January 2004, the Utility entered into a rate design settlement agreement, or rate design settlement, with representatives of major customer groups that addresses revenue allocation and rate design issues associated with the decrease in the Utility's revenue requirements resulting from the Settlement Agreement, DWR revenue requirements and other CPUC actions. On February 11, 2004, a proposed decision was issued that would adopt the rate design settlement with a modification for DWR revenues. This proposed decision, if approved by the CPUC, combined with the January 2004 CPUC decision regarding the rate freeze, provides that the Utility will no longer collect the frozen rates and surcharges. Instead, it will collect the regulatory assets arising from the Settlement Agreement, as amortized into rates, the revenue requirements established by the 2003 general rate case, or GRC, and revenue requirements established in other proceedings. The Utility has reached an agreement with several consumer groups to resolve its 2003 GRC, or GRC settlement, and set its electricity and natural gas revenue requirements and its electricity generation revenue requirement through 2006. The GRC settlement is pending CPUC approval. If the rate design settlement agreement is ultimately approved, the Utility's electricity customers would receive an electricity rate reduction of approximately 8%, on average, in March 2004, or shortly thereafter, retroactive to January 1, 2004. The Utility expects that as a result of this rate reduction, electricity operating revenues would decrease by approximately \$799 million compared to revenues generated at current rates. In addition, if the 2003 GRC settlement is not approved, the net average reduction in electricity rates and associated reduction in electricity operating revenue will be even greater.

Significant Factors Affecting Results

The Utility's results of operations will be affected by whether and when the Settlement Agreement and Plan of Reorganization are implemented. Other significant factors that affect the Utility's results of operations include:

- CPUC decisions affecting the rates that the Utility can charge for its services and determining the costs that are allowable for recovery within the Utility's rate structure;
- The amount and cost of electricity purchased;
- Other operating expenses; and
- The performance of distribution, generation, transmission and transportation operating assets.

The CPUC has broad influence over the operations of the Utility. The Utility's revenue requirements are authorized primarily by the CPUC and the CPUC approves the rates that the Utility charges its customers. The CPUC is also responsible for setting service levels and certain operating practices. These decisions have a significant impact on the amount of costs the Utility incurs. The CPUC is responsible for reviewing the Utility's capital and operating costs and in certain cases prescribes specific accounting treatment.

Electricity procurement costs historically have impacted the Utility's results of operations and financial condition. California legislation has been enacted which allows the Utility to recover substantially all its prospective wholesale electricity procurement costs and requires the CPUC to adjust rates on a timely basis to ensure that the Utility recovers its costs. Accordingly, for 2004 and beyond, electricity procurement costs are not expected to have the same impact on the Utility's results of operations that they had during the California energy crisis. However, the level of electricity procurement costs will continue to have an impact on cash flows.

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. However, there is no ratemaking mechanism for recovery of the Utility's operating and maintenance expenses. As a result, changes in the Utility's operating expenses impact the Utility's results of operations.

The Utility's distribution, generation, transmission and transportation operating assets generally consist of long-lived assets with significant construction and maintenance costs. The Utility's annual capital expenditures are expected to average approximately \$1.7 billion annually over the next five years. 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.

NEGT

On July 8, 2003, NEGТ filed a voluntary petition for relief under the provisions of Chapter 11 in the U.S. Bankruptcy Court for the District of Maryland, Greenbelt Division. The factors that caused NEGТ to take this action are discussed further below and in Note 5 of the Notes to the Consolidated Financial Statements. In anticipation of NEGТ's Chapter 11 filing, PG&E Corporation's representatives, who previously served as directors of NEGТ, resigned on July 7, 2003 and were replaced with directors who are not affiliated with PG&E Corporation. As a result, PG&E Corporation no longer retains significant influence over NEGТ. Accordingly, effective July 8, 2003, NEGТ's results are no longer consolidated with those of PG&E Corporation. NEGТ's results of operations through July 7, 2003 and for prior years have been reclassified as discontinued operations, and PG&E Corporation now accounts for its investment in NEGТ using the cost method of accounting. PG&E Corporation's net negative investment in NEGТ at December 31, 2003 was approximately \$1.2 billion.

NEGТ's future results are not expected to have a material adverse impact upon the financial condition or results of operations of PG&E Corporation or the Utility.

On February 2, 2004, NEGТ filed a second amended plan of reorganization with the bankruptcy court that, when implemented, would eliminate PG&E Corporation's equity interest in NEGТ. If NEGТ's proposed plan of reorganization or another plan that eliminates PG&E Corporation's equity in NEGТ is implemented, PG&E Corporation will reverse its investment in NEGТ and related amounts included in deferred income taxes and accumulated other comprehensive income and, as a result, recognize a material one-time net non-cash gain to earnings from discontinued operations.

NEGТ and its creditors have filed a complaint against PG&E Corporation and two PG&E Corporation officers who previously served on NEGТ's Board of Directors asserting, among other claims that NEGТ is entitled to be compensated under an alleged tax-sharing agreement for any tax savings achieved by PG&E Corporation as a result of the incorporation of the losses and deductions related to NEGТ and its subsidiaries in PG&E Corporation's consolidated federal income tax return. PG&E Corporation denies that any tax sharing agreement, whether implied or expressed, ever existed.

Reporting

The Consolidated Financial Statements of PG&E Corporation and the Utility have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and repayment of liabilities in the ordinary course of business.

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 report.

FORWARD-LOOKING STATEMENTS AND RISK FACTORS

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. These statements are based on current expectations and assumptions which management believes are reasonable and on the information currently available to management. These forward-looking statements are identified by words such as "estimates," "expects," "anticipates," "plans," "believes," "could," "should," "would," "may" and other similar expressions. Actual results could differ materially from those contemplated by the forward-looking statements.

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:

Whether and on What Terms the Plan of Reorganization is Implemented

- The timing and resolution of the pending applications for rehearing of the CPUC's approval of the Settlement Agreement and any appeals that may be filed with respect to the disposition of the rehearing applications;
- The timing and resolution of the pending appeals of the bankruptcy court's confirmation of the Plan of Reorganization;
- Whether the investment grade credit ratings and other conditions required to implement the Plan of Reorganization are obtained or satisfied; and
- Future equity and debt market conditions, future interest rates, and other factors that may affect the Utility's ability to implement the Plan of Reorganization or affect the amounts and terms of the debt proposed to be issued under the Plan of Reorganization.

Operating Environment

- Unanticipated changes in operating expenses or capital expenditures;
- The level and volatility of wholesale electricity and natural gas prices and supplies and the Utility's ability to manage and respond to the levels and volatility successfully;
- 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;
- The extent to which the Utility's residual net open position increases or decreases due to changes in customer and economic growth rates, the periodic expiration or termination of Utility or DWR power purchase contracts, the reallocation of DWR power purchase contracts, whether various counterparties are able to meet their obligations under their power sale agreements with the Utility or with the DWR, the retirement or other closure of the Utility's electricity generation facilities, the performance of the Utility's electricity generation facilities and other factors;
- The operation of the Utility's Diablo Canyon nuclear power plant, which exposes the Utility to potentially significant environmental 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 its Diablo Canyon power plant 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 other current and future ratemaking actions of the CPUC, including the outcome of the Utility's 2003 GRC;
- Prevailing governmental policies and legislative or regulatory actions generally, including those of the California legislature, U.S. Congress, the CPUC, the FERC and the Nuclear Regulatory Commission, or NRC, with regard to 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;
- 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 California investor-owned electric utilities;
- 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 utility districts, self-generation by its customers 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 and the extent to which cities, counties and others in the Utility's service territory begin directly serving the Utility's customers or combine to form community choice aggregators.

THE UTILITY'S CHAPTER 11 PROCEEDING AND CPUC SETTLEMENT AGREEMENT

On December 19, 2003, the CPUC, PG&E Corporation and the Utility entered into the Settlement Agreement and, on December 22, 2003, the bankruptcy court confirmed the Plan of Reorganization that fully incorporates the Settlement Agreement.

Terms and Financial Impact of the Settlement Agreement

The principal terms of the Settlement Agreement that will affect the Utility's results of operations and liquidity include:

Regulatory Assets. The Settlement Agreement establishes a \$2.21 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 to be amortized on a "mortgage-style" basis over nine years retroactive to January 1, 2004. Under this amortization methodology, annual after-tax collections of a \$2.21 billion regulatory asset in electricity rates are estimated to range from approximately \$140 million in 2004 to approximately \$380 million in 2012, although these amounts will be reduced as discussed below. The unamortized balance of this after-tax regulatory asset will earn a rate of return on its equity component of no less than 11.22% annually for its nine-year term. The rate of return on this regulatory asset would be eliminated if the Utility completes the refinancing discussed below. Instead, the Utility would collect from customers amounts sufficient to service the securitized debt. The net after-tax amount of any refunds, claim offsets or other credits the Utility receives from energy suppliers related to specified electricity procurement costs incurred during the California energy crisis and arising from the settlement of CPUC litigation against El Paso Natural Gas Company, or El Paso, related to electricity refunds, but not natural gas refunds, will reduce the outstanding balance of this regulatory asset. In the rate design settlement pending before the CPUC, the reduction to the regulatory asset related to the El Paso Settlement and certain other generator refunds and claim offsets is stipulated to be \$189 million, after-tax. The estimated amount will be subject to adjustment based on actual amounts received by the Utility. Additional refunds and claim offsets would further reduce this regulatory asset. Reductions of the regulatory asset reduce the amount amortized into rates.

In addition, as part of the Settlement Agreement, the CPUC will deem the Utility's adopted 2003 electricity generation rate base of approximately \$1.6 billion 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. This reaffirmation would allow recognition of an approximately \$800 million after-tax regulatory asset (which is equivalent to an approximately \$1.3 billion pre-tax regulatory asset).

The Utility expects to recognize the pre-tax amounts of the two regulatory assets once the Utility determines in accordance with accounting principles generally accepted in the United States of America, or GAAP, that these regulatory assets are probable of recovery as discussed above. This recognition would increase PG&E Corporation's and the Utility's total assets by approximately \$5.0 billion. It also will result in the recording of approximately \$2.0 billion of deferred tax liabilities that would be recognized as income tax expense. In addition, the recognition of these regulatory assets and related deferred taxes will result in a one-time non-cash gain of approximately \$3.0 billion of net income for the year of recognition, with a similar increase in PG&E Corporation's and the Utility's shareholders' equity. All these amounts will be reduced for refunds, claim offsets and other credits received prior to the initial recognition of the regulatory assets in PG&E Corporation's financial statements.

Rate-making. Under the terms of the Settlement Agreement, the CPUC has agreed to act timely upon the Utility's applications to collect in rates prudently incurred costs of any new, reasonable investment in utility plant and assets and has agreed to timely adjust the Utility's rates to ensure that it collects in rates fixed amounts to service existing rate reduction bonds, regulatory asset amortization and return and base revenue requirements. In addition, the CPUC has agreed to set the Utility's capital structure and authorized return on equity in its annual cost of capital proceedings in its usual manner. From January 1, 2004 until Moody's Investors Service, or Moody's, has issued an issuer rating for the Utility of not less than A3 or Standard & Poor's, 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 will be no less than 52%. However, for 2004 and 2005, the Utility's authorized equity ratio will equal the greater of the proportion of equity approved in the Utility's 2004 and 2005 cost of capital proceedings, or 48.6%.

The Settlement Agreement provides that the Utility's retail electricity rates are to be maintained at their existing level through 2003. In 2004, the Utility will no longer collect the revenue generated by the frozen rates and surcharges that it collected in 2003, 2002 and 2001. Instead, it will collect revenues designed to recover the regulatory assets, as amortized into rates, and the revenue requirements established by the 2003 GRC and other regulatory proceedings. Although revenue requirements would increase over previously authorized amounts if the pending GRC settlement is approved by the CPUC, the elimination of the surcharges will result in a net average reduction of electricity rates effective March 2004, or shortly thereafter, retroactive to January 1, 2004. In addition, the Utility will recognize expenses related to the amortization of the regulatory assets in 2004 and beyond, expenses not present in 2003. The amortization of the regulatory assets would have no direct impact on cash flow because amortization is a non-cash expense. The decrease in rates will, however, reduce cash flow. Other than the one-time impact of recording net income associated with recognition of the regulatory assets discussed above, overall implementation of the Settlement Agreement and related rulemaking will decrease the Utility's net income in 2004 as compared to 2003. In addition, if the GRC settlement is not approved, the amount of the rate reduction and revenue reduction will increase.

Securitization. PG&E Corporation and the Utility have agreed to seek to refinance up to a total of \$3.0 billion of the unamortized pre-tax balance of the \$2.21 billion after-tax regulatory asset, as expeditiously as practicable after the effective date of the Plan of Reorganization using a financing supported by a dedicated rate component, provided certain conditions are met. These conditions include the enactment of authorizing California legislation satisfactory to the CPUC, the Utility and The Utility Reform Network, or TURN, and that the securitization not adversely affect the Utility's credit ratings. The Utility expects to use the securitization proceeds to rebalance its capital structure in order to maintain the capital structure provided in the Settlement Agreement.

After the securitization, the rate of return on the unamortized pre-tax balance of the \$2.21 billion after-tax regulatory asset would be eliminated. Instead the Utility would collect from customers amounts sufficient to service the securitized debt. Electricity rates would be further reduced to reflect the lower cost of capital of the securitized financing, causing a corresponding decrease in the Utility's net income.

Cash Requirements of the Plan of Reorganization

The Plan of Reorganization provides for payment in full in cash of all allowed creditor claims (except for the claims of holders of approximately \$814 million of pollution control bond-related obligations that will be reinstated), plus applicable interest on claims in certain classes, and all cumulative dividends in arrears and mandatory sinking fund payments associated with the Utility's outstanding preferred stock. The following is a summary of all claims the Utility has recorded at December 31, 2003 (including all claims related to obligations that will be reinstated at the effective date of the Plan of Reorganization):

	Amount Owed
(in millions)	
Revolving line of credit	\$ 938
Bank borrowing — letters of credit for accelerated pollution control loan agreements	454
Floating rate notes	1,240
Commercial paper	873
Senior notes	680
Pollution control loan agreements	814
Medium-term notes	287
Deferrable interest subordinated debentures	300
Other long-term debt	17
Financing debt subject to compromise	5,603
Trade creditors subject to compromise	3,899
Mortgage bonds	2,741
Interest and dividends	20
Total	\$12,263

The Utility expects to pay all allowed claims (other than claims represented by reinstated obligations) on or as soon as practicable after the effective date of the Plan of Reorganization and to establish escrow accounts to pay disputed claims as they are resolved. The Utility expects that it will require approximately \$11.0 billion in cash to pay the allowed claims (including a payment of approximately \$310 million for maturing mortgage bonds to be made on March 1, 2004, pending approval of the bankruptcy court) and make the necessary escrow deposits. In addition, \$814 million outstanding under the Pollution control loan agreements will be reinstated. The Utility expects to offset allowed power procurement claims with amounts owed to the Utility by the PX. This netting reduces the cash requirement of the plan by approximately \$500 million.

The Utility expects to use approximately \$2.8 billion of cash on hand, after retirement of the mortgage bonds, to pay allowed claims and make necessary escrow deposits. In accordance with the Plan of Reorganization, the balance of the cash requirements will be met with the proceeds of a public offering of approximately \$7.4 billion of long-term debt and draws on various credit facilities.

NEGT

NEGT's Chapter 11 Filing

On July 8, 2003 NEGТ filed a voluntary petition for relief under Chapter 11. The decline in wholesale electricity prices, NEGТ's construction program, the decline of NEGТ's credit rating to below investment grade and lack of market liquidity created severe financial distress and ultimately caused it to seek protection under Chapter 11. In anticipation of NEGТ's Chapter 11 filing, PG&E Corporation's representatives, who previously served as directors of NEGТ, resigned on July 7, 2003 and were replaced with directors who are not affiliated with PG&E Corporation. As a result, PG&E Corporation no longer retains significant influence over NEGТ. NEGТ's proposed plan of reorganization provides for the elimination of PG&E Corporation's equity ownership. PG&E Corporation believes that the bankruptcy court will approve NEGТ's proposed plan of reorganization, or a plan with similar equity elimination provisions for PG&E Corporation.

As a result of NEGТ's Chapter 11 filing and the elimination of equity ownership provided for in NEGТ's proposed plan of reorganization, PG&E Corporation considers its investment in NEGТ to be an abandoned asset and

has accounted for NEGТ as discontinued operations in accordance with Statement of Financial Accounting Standards, or SFAS, No. 144, "Accounting for Impairment or Disposal of Long-Lived Assets," or SFAS No. 144. Under the provisions of SFAS No. 144, the operating results of NEGТ and its subsidiaries through July 7, 2003 and for all prior years are reported as discontinued operations in the Consolidated Statements of Operations. As of July 8, 2003, PG&E Corporation accounts for NEGТ using the cost method and NEGТ is no longer consolidated by PG&E Corporation for financial reporting purposes. The accompanying December 31, 2003 Consolidated Balance Sheet of PG&E Corporation does not reflect the separate assets and liabilities of NEGТ; rather, a liability of approximately \$1.2 billion is reflected, which represents the losses recognized by PG&E Corporation in excess of its investment in and advances to NEGТ. PG&E Corporation's investment in NEGТ will not be affected by changes in NEGТ's future financial results.

When NEGТ's proposed plan of reorganization or another plan that eliminates PG&E Corporation's equity interest in NEGТ is implemented, PG&E Corporation will reverse its investment in NEGТ and related amounts included in deferred income taxes and accumulated other comprehensive income and, as a result, recognize a material one-time net non-cash gain to earnings from discontinued operations.

NEGТ and its creditors have filed a complaint against PG&E Corporation and two PG&E Corporation officers who previously served on NEGТ's Board of Directors asserting, among other claims that NEGТ is entitled to be compensated under an alleged tax-sharing agreement for any tax savings achieved by PG&E Corporation as a result of the incorporation of losses and deductions related to NEGТ or its subsidiaries in PG&E Corporation's consolidated federal income tax return. In May 2003, PG&E Corporation received \$533 million from the Internal Revenue Service, or IRS, for an overpayment of 2002 estimated federal income taxes. NEGТ and its creditors have asserted that they have a direct interest in certain tax savings achieved by PG&E Corporation and are entitled to be paid approximately \$414 million of the funds received by PG&E Corporation (approximately \$361.5 million achieved by the incorporation of losses and deductions related to NEGТ or its subsidiaries and approximately \$53 million achieved by the incorporation of certain tax credits related to one of NEGТ's subsidiaries). Consequently, until the dispute is resolved, PG&E Corporation is treating \$361.5 million as restricted cash. PG&E Corporation anticipates continuing to incorporate losses, deductions and certain tax credits related to NEGТ or its subsidiaries in PG&E Corporation's consolidated federal tax return, until it is no longer consolidated for federal income tax purposes. NEGТ and its creditors similarly assert that NEGТ is entitled to be compensated for any tax savings resulting from inclusion of these losses in PG&E Corporation's federal tax return. PG&E Corporation denies that any tax sharing agreement, whether implied or expressed, ever existed and denies that it has any obligation to compensate NEGТ for the incorporation of losses and deductions related to NEGТ or its subsidiaries into PG&E Corporation's consolidated federal tax returns.

PG&E Corporation does not expect that the outcome of this matter will have a material adverse effect on its results of operations, financial position or liquidity.

RESULTS OF OPERATIONS

The table below details certain items from the accompanying Consolidated Statements of Operations for 2003, 2002 and 2001.

	2003	2002	2001
(in millions)			
Utility			
Electric operating revenue	\$ 7,582	\$ 8,178	\$ 7,326
Natural gas operating revenue	2,856	2,336	3,136
Cost of electricity	2,319	1,482	2,774
Cost of natural gas	1,467	954	1,832
Operating and maintenance	2,935	2,817	2,385
Depreciation, amortization and decommissioning	1,218	1,193	896
Reorganization professional fees and expenses	160	155	97
Operating income	2,339	3,913	2,478
Interest income	53	74	123
Interest expense	(953)	(988)	(974)
Other expense, net ⁽¹⁾	(9)	(27)	(41)
Income before income taxes	1,430	2,972	1,586
Income tax provision	528	1,178	596
Income before cumulative effect of a change in accounting principle	902	1,794	990
Cumulative effect of a change in accounting principle	(1)	—	—
Income available for common stock	\$ 901	\$ 1,794	\$ 990
PG&E Corporation, Eliminations and Other ⁽²⁾⁽³⁾			
Operating revenues	\$ (3)	\$ (9)	\$ (12)
Operating expenses	(7)	(50)	(147)
Operating income	4	41	135
Interest income	9	6	14
Interest expense	(194)	(236)	(104)
Other income (expense), net ⁽¹⁾	—	77	(2)
Income (loss) before income taxes	(181)	(112)	43
Income tax provision (benefit)	(70)	(41)	12
Income (loss) from continuing operations	(111)	(71)	31
Discontinued operations	(365)	(2,536)	69
Cumulative effect of changes in accounting principles	(5)	(61)	9
Net income (loss)	\$ (481)	\$ (2,668)	\$ 109
Consolidated Total ⁽³⁾			
Operating revenues	\$10,435	\$10,505	\$10,450
Operating expenses	8,092	6,551	7,837
Operating income	2,343	3,954	2,613
Interest income	62	80	137
Interest expense	(1,147)	(1,224)	(1,078)
Other income (expense), net ⁽¹⁾	(9)	50	(43)
Income before income taxes	1,249	2,860	1,629
Income tax provision	458	1,137	608
Income from continuing operations	791	1,723	1,021
Discontinued operations	(365)	(2,536)	69
Cumulative effect of changes in accounting principles	(6)	(61)	9
Net income (loss)	\$ 420	\$ (874)	\$ 1,099

- (1) Includes preferred dividend requirement as other expense.
- (2) PG&E Corporation eliminates all intersegment transactions in consolidation.
- (3) Operating results of NEGT have been reclassified as discontinued operations. See Note 5 of the Notes to the Consolidated Financial Statements.

Utility

The following presents the Utility's operating results for 2003, 2002 and 2001. As described below, net income for 2003 reflects a decline in operating revenues compared to 2002 as a result of increases in the DWR's revenue requirements and an increased cost of electricity because the Utility resumed procuring electricity to cover its residual net open position in 2003. Net income for 2002 reflects an increase in operating revenues compared to 2001 due to increased electricity surcharge collections and a decrease in amounts passed through to the DWR. Although the Utility is not able to predict all of the factors that may affect future results, results of operations in 2004 will be materially different from historical results if the Settlement Agreement is implemented, the CPUC approves the Utility's 2003 GRC settlement, and the rate design settlement is implemented.

Electric Operating Revenues

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. Under the frozen rate structure, increases in the revenues passed through to the DWR decreased the Utility's revenues.

In January 2001, the CPUC authorized the Utility to collect an electricity surcharge, the first of three surcharges intended to help the California investor-owned electric utilities pay for the high cost of wholesale electricity. The surcharges, totaling \$0.045 per kWh, were fully implemented by June 2001 and were collected through December 31, 2003, while frozen rates remained in place.

The following table shows a breakdown of the Utility's electricity operating revenue by customer class:

	2003	2002	2001
(in millions)			
Residential	\$ 3,671	\$ 3,646	\$ 3,396
Commercial	4,440	4,588	4,105
Industrial	1,410	1,449	1,554
Agricultural	522	520	525
Miscellaneous	59	316	380
Direct access credits	(277)	(285)	(461)
DWR pass-through revenue	(2,243)	(2,056)	(2,173)
Total electric operating revenues	\$ 7,582	\$ 8,178	\$ 7,326

In 2003, the Utility's electricity operating revenues decreased approximately \$596 million, or 7%, compared to 2002 mainly due to the following factors:

- Pass-through revenue to the DWR increased by approximately \$187 million, or 9%, in 2003 from 2002. This increase was mainly due to an aggregate increase of \$1.0 billion in DWR power and bond charges, partially offset by an approximately \$444 million reduction in the 2003 DWR revenue requirement and an approximately \$369 million adjustment recorded in the third quarter of 2002 to reflect required changes to the methodology used to calculate DWR pass-through revenues.

The reduction in the DWR's 2003 revenue requirement was mainly due to a September 2003 CPUC decision that reduced the DWR's approved revenue requirement for 2003. The decision also required the Utility to pass the benefit of the revenue requirement reduction on to its customers through a one-time bill credit in 2003. As a result, the approximately \$444 million

reduction in the 2003 DWR revenue requirement was offset by a corresponding reduction in electricity operating revenues for each customer class in 2003.

- The Utility recorded a regulatory liability or reserve for the potential refund of approximately \$125 million of surcharge revenues collected during 2003 as provided by the terms of the rate design settlement entered into in January 2004. The rate design settlement is subject to approval by the CPUC.
- Due to an April 2002 CPUC decision that increased baseline quantity allowances that was applied for all of 2003 but only a portion of 2002, electricity operating revenues decreased by an additional \$44 million in 2003. An increase to a customer's baseline quantity allowance increases the amount of the customer's monthly usage that is covered under the lowest possible rate and is exempt from certain surcharges.
- The decrease in electricity operating revenues was partially offset by the collection of a cost responsibility surcharge, or CRS, a non-bypassable charge to direct access customers for their share of certain costs incurred by the Utility. The CPUC implemented this surcharge on January 1, 2003 and the Utility collected approximately \$187 million in CRS revenues from direct access customers in 2003.

In 2002, the Utility's electricity operating revenues increased approximately \$852 million, or 12%, compared to 2001 mainly due to the following factors:

- The amount of CPUC authorized surcharges increased approximately \$751 million, or 34%, in 2002 from 2001. This increase reflects the collection of \$0.045 per kWh in surcharges for all of 2002 compared to the collection of \$0.01 per kWh in surcharges for substantially all of 2001 and the remaining \$0.035 per kWh in surcharges for only seven months during 2001.
- Direct access credits decreased approximately \$176 million, or 38%, in 2002 from 2001 mainly due to a decrease in the average direct access credit per kWh, partially offset by an increase in the total electricity provided to direct access customers by alternate energy service providers. The average direct access credit per kWh was lower in 2002 than in 2001 because in the beginning of 2001 the Utility used the California Power Exchange, or PX, price for wholesale electricity to calculate direct access credits. After the PX closed in January 2001, direct access credits have been calculated based on the electricity procurement component of the fully bundled rate, which has been significantly lower than the PX price. The average direct access credit decreased from \$0.116 per kWh in 2001 to \$0.038 per kWh in 2002. In 2002, alternate energy service providers supplied approximately 7,433 Gigawatt-hours, or GWh, of electricity to direct access customers, compared to approximately 3,982 GWh in 2001.
- Revenue passed through to the DWR decreased by approximately \$117 million, or 5%, in 2002 from 2001. This decrease was mainly due to a decrease in the Utility's net open position, which resulted in less DWR electricity being delivered to the Utility's customers. The decrease in the Utility's net open position was caused by increases in the number of direct access customers and in the amount of electricity the Utility was able to purchase from qualifying facilities due to renegotiated payment terms. In addition, the Utility accrued approximately \$369 million in additional pass through revenues to the DWR in 2002 due to changes proposed by the DWR to the methodology used to calculate DWR remittances. Absent this accrual, the decrease in the revenue passed through to the DWR would have been greater.

The Utility will no longer collect the frozen rates and surcharges that it collected in 2003, 2002 and 2001 after the implementation of the rate design settlement. Instead, revenues in 2004 will be based on an aggregation of individual rate components, including base revenue requirements, electricity procurement costs and the DWR revenue requirement, among others. Changes in the DWR revenue requirements will change rates charged to certain of the Utility's customers. As a result, changes in amounts passed through to the DWR will no longer affect the Utility's results of operations. A proposed decision has been issued adopting a settlement with representatives of major customer groups, which, if approved by the CPUC, will reduce electricity rates by approximately 8.0%, on average and result in a reduction of electricity operating revenues of approximately \$799 million.

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 generation facilities. 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:

	2003	2002	2001
(in millions)			
Cost of purchased power	\$ 2,449	\$ 1,980	\$ 3,224
Proceeds from surplus sales allocated to the Utility	(247)	—	—
Fuel used in own generation	117	97	102
Adjustments to purchased power accruals	—	(595)	(552)
Total net cost of electricity	\$ 2,319	\$ 1,482	\$ 2,774
Average cost of purchased power per kWh	\$ 0.076	\$ 0.081	\$ 0.143
Total purchased power (GWh)	32,249	24,552	22,592

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% because 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 costs was partially offset by proceeds from surplus electricity sales. 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. 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 on 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.
- 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 Independent System Operator, or ISO, charges and to adjust for the amount previously accrued as payable to the DWR for its 2001 revenue requirement. There was no comparable reduction in 2003.

In 2002, the Utility's cost of electricity decreased approximately \$1.3 billion, or 47%, compared to 2001 because the Utility's average cost of purchased power decreased compared to 2001 mainly due to the significantly lower prices for electricity after the energy market stabilized in the second half of 2001. In addition, the DWR purchased all of the electricity needed to meet the Utility's net open position for all of 2002, whereas in 2001 the Utility purchased the electricity itself through the PX market through the first half of January 2001.

In 2002, FERC and CPUC decisions allowed the Utility to reverse previously accrued ISO charges and adjust previously accrued DWR pass-through revenues, reducing the cost of electricity by a net of approximately \$595 million. In 2001, the Utility recorded approximately \$552 million for the market value of terminated bilateral contracts, reducing the cost of electricity by approximately \$552 million for that year. The net effect of these adjustments contributed to an additional decrease of approximately \$43 million in the cost of electricity in 2002.

The Utility's cost of electricity in 2004 will be dependent upon electricity prices and the Utility's residual net open position.

Natural Gas Operating Revenues

The following table shows a breakdown of the Utility's natural gas operating revenues:

	2003	2002	2001
(in millions)			
Bundled natural gas revenues	\$2,572	\$2,020	\$2,761
Transportation service-only revenues	284	316	375
Total natural gas operating revenues	\$2,856	\$2,336	\$3,136
Average bundled revenue per Mcf of natural gas sold	\$ 9.22	\$ 7.16	\$10.19
Total bundled natural gas sales (in millions of Mcf)	279	282	271

In 2003, the Utility's total natural gas operating revenues increased approximately \$520 million, or 22%, compared to 2002 mainly due to the following factors:

- Bundled natural gas revenues increased by approximately \$552 million, or 27%, in 2003 from 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 thousand cubic feet, or Mcf, of natural gas sold in 2003 increased \$2.06, or 29%, compared to 2002. Natural gas prices increased in 2003 mainly due to a shortage in natural gas supply and lower storage reserves.
- Transportation service-only revenues decreased by approximately \$32 million, or 10%, in 2003 from 2002 mainly 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.

In 2002, the Utility's total natural gas operating revenues decreased approximately \$800 million, or 26%, compared to 2001 mainly due to the following factors:

- Bundled natural gas revenues decreased by approximately \$741 million, or 27%, in 2002 from 2001 mainly due to a lower average cost of natural gas. The average bundled revenue per Mcf of natural gas sold in 2002 decreased \$3.03, or 30%, compared to 2001. Natural gas prices decreased in 2002 mainly due to an overall increase in natural gas supply and higher storage reserves.
- Transportation service-only revenue decreased by approximately \$59 million, or 16%, in 2002 from 2001 mainly due to a decrease in demand for gas transportation services by natural gas-fired electric generators in California.

The Utility's natural gas revenues in 2004 are expected to increase due to natural gas distribution rate increases in the GRC settlement 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 its intrastate pipeline, which are included in operating and maintenance expense. The following table shows a breakdown of the Utility's cost of natural gas:

	2003	2002	2001
(in millions)			
Cost of natural gas sold	\$1,336	\$ 853	\$1,593
Cost of natural gas transportation	131	101	239
Total cost of natural gas	\$1,467	\$ 954	\$1,832
Average cost per Mcf of natural gas sold	\$ 4.79	\$3.02	\$ 5.88
Total natural gas sold (in millions of Mcf)	279	282	271



In 2003, the Utility's total cost of natural gas sold increased approximately \$513 million, or 54%, compared to 2002 mainly due to the following factors:

- The Utility's cost of natural gas sold increased approximately \$483 million, or 57%, in 2003 from 2002 mainly due to an increase in the average cost of natural gas sold in 2003 of \$1.77 per Mcf, or 59%.
- The Utility's cost of natural gas transportation increased by approximately \$30 million, or 30%, in 2003 from 2002 mainly due to pipeline transportation charges paid to 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.

In 2002, the Utility's total cost of natural gas sold decreased approximately \$878 million, or 48%, compared to 2001 mainly due to the following factors:

- The Utility's cost of natural gas sold decreased by approximately \$740 million, or 46%, in 2002 from 2001 mainly due to a decrease of \$2.86 per Mcf, or 49%, in the average cost of natural gas sold.
- The Utility's cost of natural gas transportation decreased by approximately \$138 million, or 58%, in 2002 from 2001 mainly due to approximately \$111 million in costs recognized in 2001 related to the involuntary termination of natural gas transportation hedges caused by a decline in the Utility's credit rating. There were no similar events in 2002.

The Utility's cost of natural gas sold in 2004 will be 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 its electricity and natural gas facilities, maintenance expenses, customer accounts and service expenses, administrative and general expenses, and the net deferral of revenues and expenses based on the difference between certain revenues and expenses recognized under GAAP and those revenues and expenses recognized for regulatory purposes.

In 2003, the Utility's operating and maintenance expenses increased 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 half-cent 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%.

These increases were partially offset by a net increase in deferred electricity transmission-related costs compared to 2002. Electricity transmission-related costs are included in the cost of electricity and consist mainly of charges imposed by the ISO for grid management services. To the extent the Utility does not receive revenues sufficient to recover electricity transmission-related costs, the costs are deferred through a reduction of operating and maintenance expense until recovered in rates.

In 2002, the Utility's operating and maintenance expenses increased approximately \$432 million, or 18%, compared to 2001 mainly due to the following factors:

- Employee benefit plan-related expenses increased approximately \$115 million in 2002 from 2001 mainly due to a 7% decrease in returns on plan investments and lower interest rates, which caused a decrease in the discount rate used to calculate the present value of the Utility's benefit obligations;
- Environmental related expenses increased approximately \$54 million in 2002 from 2001 mainly due to an increase in third party liabilities;
- The Utility's new customer billing system, which was implemented at the end of 2002, increased customer accounts and service expenses by approximately \$23 million, or 9%, in 2002 from 2001. The increased cost in 2002 resulted from pre-implementation testing, validation and training costs;

- The net deferred electricity transmission-related costs increased approximately \$142 million in 2002 from 2001; and
- The Utility began deferring over-collected electricity revenue associated with the rate reduction bonds in 2002. Total deferred revenue was approximately \$85 million in 2002.

Depreciation, Amortization and Decommissioning

In 2003, the Utility's depreciation, amortization and decommissioning expenses increased approximately \$25 million, or 2%, compared to 2002 mainly due to an overall increase in the Utility's plant assets.

In 2002, the Utility's depreciation, amortization and decommissioning expenses increased approximately \$297 million, or 33%, compared to 2001 mainly due to the amortization of approximately \$290 million of the rate reduction bond regulatory asset that began in January 2002.

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 \$160 million in 2003, \$155 million in 2002 and \$97 million in 2001. Upon implementation of the Plan of Reorganization and repayment in cash of substantially all allowed creditor claims and applicable interest and dividends, as discussed in the "Cash Requirements of the Plan of Reorganization" section above, the Utility will no longer incur reorganization fees and expenses.

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 approximately \$21 million, or 28%, in 2003 from 2002 and approximately \$49 million, or 40%, in 2002 from 2001. Decreases for both periods were mainly due to lower average interest rates earned on the Utility's short-term investments.

Interest Expense

In 2003, the Utility's interest expense decreased 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. This decrease was partially offset by the recording of approximately \$38 million interest payable to the DWR in 2003 based upon a CPUC decision issued in January 2004. The interest payable to the DWR compensates the DWR for prior underpayments resulting from ambiguities in the formula that determined the DWR remittance rate that were resolved in September 2003. The Utility has filed an application for rehearing of this decision with the CPUC.

In 2002, the Utility's interest expense increased approximately \$14 million, or 1%, compared to 2001 due to the Utility's Chapter 11 proceeding, which resulted in higher negotiated interest rates and an increased level of unpaid debts accruing interest.

As discussed above in the Cash Requirements of the Plan of Reorganization section, the Utility's ongoing interest expense will be dependent upon the size of the refinancing and associated rates established at the effective date of the Plan of Reorganization.

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.

In connection with refinancings of PG&E Corporation's debt in 2001, PG&E Corporation granted to affiliates of the lenders warrants to purchase up to 5% of NEG's outstanding common stock. These warrants were originally recorded at their fair value of approximately \$151 million. The fair value of the warrants is marked to market at each reporting period. Changes in the fair value of the warrants are recorded as operating expense until exercised. This expense is not allocated to affiliates nor is it eliminated. Increases in the fair value of the warrants are recorded as operating expense and conversely declines in the fair value of NEG warrants are recorded as a contra expense. The contra expense reflects the decline in the value of the unexercised warrants to their current recorded value of zero, of approximately \$140 million in 2002 and approximately \$11 million in 2001.

Interest Expense

PG&E Corporation's interest expense is not allocated to its affiliates. In 2003, PG&E Corporation's interest expense decreased by approximately \$42 million, or 18%, compared to 2002. The decrease is 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 of unamortized loan fees, loan discounts and prepayment fees when it repaid loans due originally in 2006. During the third quarter of 2002, PG&E Corporation wrote off \$153 million of unamortized loan fees and discounts when it repaid \$600 million of principal and modified a \$420 million loan under PG&E Corporation's credit agreement. This later write-off was substantially responsible for the increase in interest expense in 2002 compared to 2001.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

At December 31, 2003, PG&E Corporation had approximately \$4.4 billion of consolidated cash and cash equivalents and restricted cash, of which approximately \$764 million was restricted. PG&E Corporation and the Utility maintain separate bank accounts. At December 31, 2003, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately \$673 million and restricted cash of \$361.5 million. At December 31, 2003 the Utility had cash and cash equivalents and restricted cash of approximately \$3.4 billion. 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.

Utility

At December 31, 2003, the Utility had approximately \$3.4 billion of cash and cash equivalents. The principal source of the Utility's cash is payments from its customers. Since wholesale electricity prices moderated and electricity surcharges were fully implemented in mid-2001, the cash generated by the Utility's operations has exceeded its ongoing cash requirements.

During its Chapter 11 proceeding, the Utility has not had access to the capital markets and has met all its ongoing cash requirements, including its capital expenditures requirements, with cash generated by its operations. In addition, the Utility has paid interest on certain pre-petition liabilities and repaid the principal of maturing mortgage bonds with bankruptcy court approval. The Utility expects to pay allowed creditor claims from the proceeds of a public offering of long-term debt, cash on hand, and draws on revolving credit and accounts receivable facilities established in connection with the implementation of the Plan of Reorganization. The Utility also will establish an escrow account for disputed claims and deposit cash into these accounts to pay the claims as they are resolved.

Of the Utility's cash and cash equivalents at December 31, 2003, approximately \$403 million is restricted as to its use. The restrictions arise from deposits under certain third party agreements, amounts held in escrow as collateral required by the ISO and deposits securing workers' compensation obligations.

After the effective date of its Plan of Reorganization, the Utility is expected to fund its operating expenses and its capital expenditures program from internally generated funds. The Utility will maintain commercial bank lines and other short-term borrowing facilities in order to provide sufficient liquidity to fund seasonal changes in working capital, balancing account under-collections, and credit support for collateralized procurement activities. The Utility is also expected to utilize a portion of its internally generated funds to make scheduled debt service payments and achieve the target capital structure provided for in the Settlement Agreement by late 2005. Once the Utility reaches this target capital structure, it will commence distributions to PG&E Corporation in the form of dividends and stock repurchases. Thereafter, a small portion of the Utility's capital expenditures program is expected to be funded with the issuance of new debt securities.

Operating Activities

The Utility's cash flows from operating activities consist of monthly sales to its customers and 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 2003, 2002 and 2001 were as follows:

	2003	2002	2001
(in millions)			
Net income	\$ 923	\$ 1,819	\$1,015
Non-cash (income) expenses:			
Depreciation, amortization and decommissioning	1,218	1,193	896
Net reversal of ISO accrual	—	(970)	—
Change in accounts receivable	(590)	212	105
Change in accrued taxes	48	(345)	1,415
Other uses of cash:			
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(87)	(1,442)	(16)
Other changes in operating assets and liabilities	458	667	1,350
Net cash provided by operating activities	\$1,970	\$ 1,134	\$4,765

Although net income decreased by approximately \$896 million in 2003 compared to 2002, in 2003, net cash provided by operating activities increased by approximately \$836 million compared to 2002 mainly due to the following factors:

- Payments on amounts classified as liabilities subject to compromise decreased by approximately \$1.3 billion in 2003, compared to 2002 due to significant pre-petition and post-petition payments made in 2002 under bankruptcy court-approved settlements;
- Net cash provided by operating activities was partially offset by an increase in accounts receivable. 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; 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.

In 2002, the net cash provided by operating activities decreased by approximately \$3.6 billion compared to 2001, mainly due to the following factors:

- The Utility's filing of its Chapter 11 petition in April 2001 automatically stayed all payments on then-existing liabilities. After the filing, the Utility resumed paying its ongoing expenses in the ordinary course of business. As a result, the growth in accounts payable was approximately \$1.1 billion lower in 2002 than in 2001;
- The Utility received an approximately \$1.1 billion income tax refund in 2001 and no comparable refund was received in 2002;
- In 2002, the Utility repaid approximately \$901 million in pre-petition liabilities owed to qualifying facilities under bankruptcy court-approved agreements; and
- In 2002, under a bankruptcy court order, the Utility paid approximately \$1.0 billion in pre-petition and post-petition interest to holders of certain undisputed claims, trade creditors and certain other general unsecured creditors. These interest payments included approximately \$433 million of accrued interest on financial debt previously classified as liabilities subject to compromise.

The Utility will maintain commercial bank lines of credit and other short-term borrowing facilities in order to provide sufficient liquidity to fund seasonal changes in working capital, balancing account under-collections, and credit support for collateralized procurement activities.

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 2003, 2002 and 2001. 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 2003, 2002 and 2001 were as follows:

	2003	2002	2001
(in millions)			
Capital expenditures	\$(1,698)	\$(1,546)	\$(1,343)
Net proceeds from sale of assets	49	11	—
Other investing activities, net	(114)	26	5
Net cash used by investing activities	\$(1,763)	\$(1,509)	\$(1,338)

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.

In 2002, net cash used by investing activities increased by approximately \$171 million compared to 2001 mainly due to an increase in capital expenditures related to electricity transmission substation and line improvements intended to improve system reliability.

Financing Activities

During its Chapter 11 proceeding, the Utility's financing activities have been limited to repayment of secured debt obligations as authorized by the bankruptcy court. During this period, the Utility has not had access to the capital markets. As discussed below, the Utility expects to issue significant amounts of debt in connection with the implementation of the Plan of Reorganization and establish revolving credit and accounts receivable facilities to provide additional liquidity at and after the effective date of the Plan of Reorganization.

The Utility's cash flows from financing activities for 2003, 2002 and 2001 were as follows:

	2003	2002	2001
(in millions)			
Net repayments under credit facilities and short-term borrowings	\$ —	\$ —	\$ (28)
Net long-term debt, matured, redeemed or repurchased	(281)	(333)	(111)
Rate reduction bonds matured	(290)	(290)	(290)
Other financing activities, net	—	—	(1)
Net cash used by financing activities	\$(571)	\$(623)	\$(430)

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. PG&E Funding, LLC, a wholly owned subsidiary of the Utility, also repaid approximately \$290 million in principal on its rate reduction bonds. The rate reduction bonds are 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. The Utility remits the collection of these billings to PG&E Funding, LLC on a daily basis.

In 2002, net cash used by financing activities increased by approximately \$193 million compared to 2001. With bankruptcy court approval, the Utility repaid approximately \$333 million in principal on its mortgage bonds that

matured in March 2002. PG&E Funding, LLC also repaid approximately \$290 million in principal on its rate reduction bonds during each of 2001 and 2002.

Financing activities used approximately \$430 million of net cash in 2001 mainly for repayments of long-term debt and rate reduction bonds. The repayment of long-term debt included payments of approximately \$18 million on medium-term notes and approximately \$93 million for mortgage bonds before the Utility's Chapter 11 filing.

PG&E Corporation

At December 31, 2003 PG&E Corporation's stand-alone cash and cash equivalents balance was approximately \$673 million. PG&E Corporation's sources of funds are dividends from the Utility, issuance of its common stock and external financing. The Utility did not pay any dividends to PG&E Corporation in 2003, 2002 or 2001. PG&E Corporation also has \$361.5 million of restricted cash which is recorded in noncurrent other assets at December 31, 2003. This restricted cash pertains to the tax dispute with NEGT described above.

Operating Activities

PG&E Corporation's cash flows from operating activities consist mainly of billings to its affiliates 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 interest costs are not passed on to its affiliates nor are the benefits or detriments of the consolidated tax return. The benefits of the consolidated tax return have created cash flow from operating activities for PG&E Corporation during 2003, 2002 and 2001. NEGT's tax dispute with PG&E Corporation is discussed above.

PG&E Corporation's consolidated cash flows from operating activities for 2003, 2002 and 2001 were as follows:

	2003	2002	2001
(in millions)			
Net income	\$ 420	\$ (874)	\$1,099
Loss from discontinued operations	365	2,536	(69)
Cumulative effect of changes in accounting principles	6	61	(9)
Net income from continuing operations	791	1,723	1,021
Non-cash (income) expenses:			
Depreciation, amortization and decommissioning	1,222	1,196	899
Deferred income taxes and tax credits-net	190	(281)	(356)
Other deferred charges and noncurrent liabilities	857	921	(857)
Loss from retirement of long-term debt	89	153	—
Other changes in operating assets and liabilities:	(647)	(2,898)	4,188
Net cash provided by operating activities	\$2,502	\$ 814	\$4,895

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 as discussed above, 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.

In 2002, PG&E Corporation's cash flows provided by operating activities decreased by approximately \$4.1 billion compared to 2001, mainly due to the continued operation of the Utility under Chapter 11 and the prior year impact of an income tax refund.

Investing Activities

PG&E Corporation's stand-alone cash flows for investing activities consist mainly of the purchase of office equipment and computers and totaled approximately \$0.4 million for 2003, \$1.0 million for 2002 and \$3.6 million for 2001.

Financing Activities

PG&E Corporation's cash flows from financing activities consist mainly of cash generated from debt refinancings and the issuance of common stock.

PG&E Corporation's cash flows from financing activities for 2003, 2002 and 2001 were as follows:

	2003	2002	2001
(in millions)			
Net repayments under credit facilities	\$ —	\$ —	\$(959)
Net proceeds from long-term debt issued	581	847	907
Long-term debt matured, redeemed or repurchased	(1,068)	(1,241)	(111)
Rate reduction bonds matured	(290)	(290)	(290)
Common stock issued	166	217	15
Dividends paid	—	—	(109)
Other, net	(4)	—	(2)
Net cash used by financing activities	\$ (615)	\$ (467)	\$(549)

In March 2001, PG&E Corporation borrowed approximately \$1.0 billion under a credit facility and used the proceeds to pay commercial paper, borrowings under PG&E Corporation's then-existing revolving credit facility and a dividend to its shareholders declared in the fourth quarter of 2000. The credit facility also provided affiliates of the lenders with options to purchase up to 2 or 3% of NEG's outstanding common stock (depending on how long the loans were outstanding) at an exercise price of \$1.00. Options representing 3% of NEG were exercised during the first quarter of 2003.

The March 2001 credit facility was amended in November 2001 to extend the term of the credit facility from March 2, 2003 to March 2, 2004 and allow PG&E Corporation to further extend the term for two additional one-year periods. PG&E Corporation issued the lenders additional options equal to 1% of NEG's common stock. The credit facility was further amended in March 2002 to make the two additional one-year extensions, subject to certain conditions, including an accelerated principal payment and the grant of additional options to purchase 1% of NEG's outstanding common stock.

This credit facility was refinanced in June 2002, through the issuance of \$1.02 billion of debt under an amended credit agreement, which also granted the lenders warrants to purchase approximately 2,397,541 shares of PG&E Corporation's common stock at an exercise price of \$0.01 per share. Under the June 2002 amended agreement, the options granted to the lenders in March 2001 and 2002 to purchase 1% of NEG's outstanding common stock for each one-year extension, were reduced to approximately 0.87%.

In August 2002, PG&E Corporation made a voluntary prepayment of \$600 million of principal plus interest of \$7 million, reducing the outstanding balance under the amended credit agreement to \$420 million.

In October 2002, the amended credit agreement was further amended to increase the size of the facility by \$300 million to a total of \$720 million. PG&E Corporation borrowed the \$300 million in January 2003, receiving net proceeds of approximately \$237 million after funding an interest reserve account of approximately \$54 million and paying a funding fee of approximately \$9 million. In connection with the amendment, PG&E Corporation issued to the lenders additional warrants to purchase 2,669,390 shares of PG&E Corporation's common stock, at an exercise price of \$0.01 per share.

Also, in June 2002, PG&E Corporation issued \$280 million of 7.50% convertible subordinated notes due June 30, 2007. PG&E Corporation may convert the notes at any time into 18,558,655 shares of PG&E Corporation's common stock. In October 2002, the notes were amended to eliminate the cross-default provisions related to NEG, increase the interest rate to 9.50%, extend the maturity to June 30, 2010 and give the holders a one-time right to require PG&E Corporation to repurchase the notes on June 30, 2007 at a purchase price equal to the principal amount of the notes. The holders of the convertible notes are also entitled to receive dividend payments as if they hold the common shares subject to the conversion feature.

In July 2003, PG&E Corporation issued \$600 million of 6 7/8% Senior Secured Notes due 2008. The notes are secured by a pledge of approximately 94% of the Utility's outstanding common stock and are senior to all PG&E Corporation's existing and future subordinated debt, including its convertible subordinated notes. Interest on the notes is payable semi-annually in arrears on January 15 and July 15, commencing January 15, 2004. PG&E Corporation can

redeem the notes at any time at its option at a premium. In addition, in certain circumstances involving a change of control, spin-off, or reorganization event, PG&E Corporation is required to offer to purchase the notes. The approximately \$581 million in net proceeds of the offering, together with cash on hand, were used to repay \$720 million outstanding under PG&E Corporation's credit agreement, accrued in-kind interest of approximately \$15 million and a prepayment premium of approximately \$52 million.

In 2003, PG&E Corporation's cash flows from financing activities include approximately \$166 million from the issuance of common stock for 401(k) plan stock purchases and stock option and warrant exercises. PG&E Corporation's cash flows from financing activities include approximately \$217 million in 2002 and approximately \$15 million in 2001 for similar common stock issuances. In addition, approximately \$109 million of dividends were paid in 2001 with no comparable activity in 2002 or 2003.

Future Liquidity

After the effective date of the Plan of Reorganization, the Utility expects to fund its operating expenses and capital expenditures substantially from internally generated funds, although it may issue debt for these purposes in the future. In addition, on or about the effective date of the Plan of Reorganization, the Utility expects to establish one or more credit facilities in the amount of approximately \$1.5 billion. These facilities are intended to be used for the purposes of funding its operating expenses and seasonal fluctuations in working capital, providing letters of credit and paying a small portion of the allowed claims under the Plan of Reorganization. The Utility currently anticipates approximately \$800 million of these credit facilities will be available for revolving borrowings and the remaining approximately \$650 million will be allocated to letters of credit. While the Utility expects to enter into these new credit facilities on or about the effective date of the Plan of Reorganization, there can be no assurance that it will be successful and, if so, on what terms.

The Utility expects that the cash it will retain after the effective date of the Plan of Reorganization, together with cash from operating activities and available under the credit facilities it expects to establish, as described above, will provide for seasonal fluctuations in cash requirements and will be sufficient to fund its operations and its capital expenditures for the foreseeable future.

Dividend Policy

Historically, in determining whether to, and at what level to, declare a dividend, PG&E Corporation has considered a number of financial factors, including sustainability, financial flexibility, and competitiveness with investment opportunities of similar risk, as well as other factors, including the regulatory and legislative environment, operating performance, and capital and financial resources in general.

Other than payment in 2001 of the dividend declared in the fourth quarter of 2000, PG&E Corporation has not declared or paid a dividend in 2003, 2002 or 2001. Further, the 6 7/8% Senior Secured Notes issued by PG&E Corporation prohibit PG&E Corporation from declaring or paying dividends or repurchasing its common stock. Notwithstanding this restrictive covenant, PG&E Corporation may declare a dividend or repurchase a portion of its common stock if:

- Certain financial criteria are met;
- The 6 7/8% Senior Secured Notes are rated Baa3 or better by Moody's and BBB- or better by S&P; or
- Following the implementation of a plan of reorganization by the Utility, the dividends or stock repurchases are funded from proceeds of cash distributions to PG&E Corporation from the Utility.

The Utility has not declared or paid any common or preferred dividends in 2003, 2002 or 2001. While in Chapter 11, the Utility is prohibited from paying any common or preferred dividends without bankruptcy court approval. Among other restrictions, the Utility must maintain a capital structure authorized by the CPUC. The Utility expects to achieve the target capital structure provided for in the Settlement Agreement by the second half of 2005.

CAPITAL EXPENDITURES AND COMMITMENTS

The following table provides information about the Utility's and PG&E Corporation's contractual obligations and commitments at December 31, 2003. This table includes obligations based on their existing terms. The Utility expects to repay some of these obligations on, or as soon as practicable after, the effective date of the Plan of Reorganization. This table does not include payments on the long-term debt the Utility expects to issue, and credit facilities it expects to establish, in connection with the Plan of Reorganization.

	Payment due by period				
	Total	Less than one year	1-3 years	3-5 years	More than 5 years
Utility off balance sheet commitments:					
Power purchase agreements ⁽¹⁾ :					
Qualifying facilities	\$19,960	\$1,590	\$3,090	\$2,880	\$12,400
Irrigation district and water agencies	624	69	118	113	324
Other power purchase agreements	435	96	126	85	128
Natural gas supply and transportation	1,000	852	141	7	—
Nuclear fuel	194	90	25	27	52
Other commitments ⁽²⁾	238	126	78	29	5
Employee benefits:					
Pension ⁽³⁾	386	129	257	—	—
Postretirement benefits other than pension ⁽³⁾	194	65	129	—	—
Total Utility off balance sheet commitments	23,031	3,017	3,964	3,141	12,909
Long-term debt:					
Liabilities not subject to compromise:					
Fixed rate principal obligations	2,741	310	289	—	2,142
Liabilities subject to compromise:					
Fixed rate principal obligations	1,184	225	697	1	261
7.90% Deferrable Interest Subordinated Debentures	300	—	—	—	300
Variable rate principal obligations	614	349	265	—	—
Rate reduction bonds	1,160	290	580	290	—
Preferred dividends and redemption requirements ⁽⁴⁾	198	41	31	79	47
PG&E Corporation:					
Long-term debt:					
6 7/8% Senior Secured Notes	600	—	—	600	—
Convertible Subordinated Notes	280	—	—	—	280
Other long-term debt	3	—	—	3	—
Operating leases	9	4	3	2	—

(1) This table does not include DWR allocated contracts because the DWR is currently legally and financially responsible for these contracts.

(2) Includes commitments for operating lease agreements mostly for office space in the aggregate amount of approximately \$91 million, capital infusion agreements for limited partnership interests in the aggregate amount of approximately \$16 million, contracts to retrofit generation equipment at the Utility's facilities in the aggregate amount of approximately \$62 million, load-control and self-generation CPUC initiatives in the aggregate amount of approximately \$35 million, contracts for local and long-distance telecommunications and other software in the aggregate amount of approximately \$16 million and capital expenditures for which the Utility has contractual obligations or firm commitments.

(3) Contribution estimates conform to forecasted amounts in the pending 2003 GRC. Actual contributions are dependent upon the outcome of the 2003 GRC. Contribution estimates after 2006 are subject to future GRC test years.

(4) Preferred dividend and redemption requirement estimates beyond 5 years do not include non-redeemable preferred stock dividend payments as these continue in perpetuity.

Contractual Commitments

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 Facilities. The Utility's power purchase agreements with qualifying facilities require the Utility to pay for energy and capacity. Energy payments are based on the qualifying facility's actual electricity 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 facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreement. Capacity payments total approximately \$500 million annually. The energy payments under the power purchase agreements with the qualifying facilities are typically based upon a CPUC-approved short-run avoided cost that is currently indexed to natural gas prices. Avoided costs are the incremental costs that an electric utility would incur to generate or purchase electricity but for the purchase from the qualifying facilities. As a result of the California energy crisis and the Utility's Chapter 11 filing, in July 2001, 197 qualifying facilities amended their contracts to fix their energy payments at \$0.054 per kWh through July 2006. The remaining qualifying facility contracts calculate payment based on short-run avoided cost. Beginning in August 2006, the energy payments under all qualifying facility contracts will revert back to the short-run avoided cost rates.

At December 31, 2003, the Utility had qualifying facility power purchase agreements with 300 qualifying facilities for approximately 4,400 megawatts, or MW, that are in operation. Agreements for approximately 4,000 MW expire between 2004 and 2028. Qualifying facility power purchase agreements for approximately 400 MW have no specific expiration dates and will terminate only when the owner of the qualifying facility exercises its termination option. On January 22, 2004, the CPUC adopted a decision that requires California investor-owned electric utilities to allow owners of qualifying facilities with power purchase agreements expiring before the end of 2005 to extend these contracts for five years. Qualifying facility power purchase agreements accounted for approximately 20% of the Utility's 2003 electricity sources, approximately 25% of its 2002 electricity sources and approximately 21% of its 2001 electricity sources. No single qualifying facility power purchase agreement accounted for more than 5% of the Utility's electricity sources during any of these periods.

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 made to qualifying facilities. Under the Settlement Agreement, the net after-tax amount of any qualifying facility refunds that the Utility actually realizes in cash, claim offsets or other credits would reduce the \$2.21 billion after-tax regulatory asset. While PG&E Corporation and the Utility are unable to estimate the outcome of this proceeding, they believe the proceeding will not have a material adverse effect on their financial condition or results of operations.

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 of whether any hydroelectric power is supplied and variable payments for operating and maintenance costs incurred by the suppliers. These contracts expire on various dates from 2004 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 5% of its 2003 electricity sources, approximately 4% of its 2002 electricity sources and approximately 3% of its 2001 electricity sources.

Other Power Purchase Agreements

Electricity Purchases to Satisfy the Residual Net Open Position. On January 1, 2003, the Utility resumed buying electricity to meet its residual net open position. During 2003, more than 14,000 GWh of energy was bought and sold in the wholesale market to manage the 2003 residual net open position. Most of the Utility's contracts entered into in 2003 had terms of less than one year. During 2004, the Utility plans to enter into contracts of longer duration to satisfy its near-term residual net open position.

Renewable Energy Requirement. California law requires that, beginning in 2003, each California investor-owned electric utility 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 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 estimates the annual procurement target will initially require it to purchase approximately 750 GWh of electricity from renewable resources each year. The Utility

met its 2003 commitment and the CPUC has approved several contracts intended to meet its 2004 renewable energy requirement.

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 purchase contracts have fluctuated, generally based on market conditions. At December 31, 2003, the Utility had a \$10 million collateralized standby letter of credit and a pledge of its core natural gas customer accounts receivable for the purpose of securing the purchase of natural gas. The core natural gas inventory also may be pledged, but only if the amount of the Utility's natural gas customer accounts receivable is less than the amount that it owes to natural gas suppliers. To date, the amount of the Utility's accounts receivable pledge has been sufficient. The pledged amount of customer accounts receivable was approximately \$561 million at December 31, 2003 and \$513 million at December 31, 2002. The amount owed to natural gas suppliers was approximately \$96 million at December 31, 2003 and \$29 million at December 31, 2002. It is anticipated that the pledge of the natural gas customer accounts receivable and natural gas inventory will be replaced with letters of credit no later than the effective date of the Plan of Reorganization.

The Utility also has long-term natural gas transportation service agreements with various Canadian and interstate pipeline companies. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity as well as volumetric transportation charges. The total demand charges that the Utility will pay each year may change periodically as a result of changes in regulated tariff rates. The total demand and volumetric transportation charges the Utility incurred under these agreements were approximately \$131 million in 2003, \$101 million in 2002 and \$239 million in 2001.

Nuclear Fuel Agreements

The Utility has purchase agreements for nuclear fuel. These agreements have terms ranging from two to five years and are intended to ensure long-term fuel supply. These agreements are with a number of large, well-established international producers of nuclear fuel in order to diversify the Utility's commitments and provide security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published information. Deliveries provided under nine of the eleven contracts in place at the end of 2003 will end by 2005. In most cases, the Utility's nuclear fuel agreements are requirements-based. Payments for nuclear fuel amounted to approximately \$57 million in 2003, \$70 million in 2002 and \$50 million in 2001.

WAPA Commitments

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 systems by WAPA, and the integration of the Utility's and WAPA's customer demands and electricity resources. These contracts give the Utility access to WAPA's excess hydroelectric power and obligate the Utility to provide WAPA with electricity when its resources are not sufficient to meet its requirements. The contracts are scheduled to terminate on December 31, 2004, but termination is subject to FERC approval, which the Utility expects to receive.

The contractual commitments table above does not include the Utility's WAPA commitment because the costs to fulfill the Utility's obligations to WAPA cannot be accurately estimated at this time. Both the purchase price and the amount of electricity WAPA will need from the Utility in 2004 are uncertain. However, the Utility expects that the cost of meeting its contractual obligations to WAPA will be greater than the amount that the Utility receives from WAPA under the contracts. Although it is not indicative of future sales commitments or sales-related costs, the Utility's estimated net costs, based upon its portfolio, including DWR power and bond charges, and after subtracting revenues received from WAPA, for electricity delivered under the contracts were approximately \$233 million in 2003, \$127 million in 2002 and \$350 million in 2001.

Transmission Control Agreement

The Utility is a party to a Transmission Control Agreement, or TCA, with the ISO and other participating transmission owners. As a transmission owner, the Utility is required to give two years notice and receive regulatory approval if it wishes to withdraw from the TCA. Under this agreement, the transmission owners, which also include Southern California Edison, or SCE, San Diego Gas & Electric Company and several municipal utilities, assign

operational control of their electricity transmission systems to the ISO. In addition, as a party to the TCA, the Utility is responsible for a share of the costs of reliability must-run, or RMR, agreements between the ISO and owners of the power plants subject to RMR agreements, or RMR Plants. The Utility also is an owner of some of these RMR Plants for which the Utility receives revenue from the ISO. Under the RMR agreements, RMR Plants must remain available to generate electricity when needed for local transmission system reliability upon the ISO's demand.

At December 31, 2003, the ISO had RMR agreements for which the Utility could be obligated to pay the ISO an estimated \$446 million in net costs during the period January 1, 2004 to December 31, 2005. These costs are recoverable under applicable ratemaking mechanisms.

It is possible that the Utility may receive a refund of RMR costs that the Utility previously paid to the ISO. In June 2000, a FERC administrative law judge issued an initial decision approving rates that, if affirmed by the FERC, would require the subsidiaries of Mirant Corporation, or Mirant, 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 \$340 million, including interest, for availability of Mirant's RMR Plants under these agreements. However, 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. The Utility is unable to predict at this time when the FERC will issue a final decision on this issue, what the FERC's decision will be, and the amount of any refunds, which may be impacted by Mirant's Chapter 11 filing. It is uncertain how the resolution of this matter would be reflected in rates.

Other Commitments

The Utility has other commitments relating to operating leases, capital infusion agreements, equipment replacements, software licenses, the self-generation incentive program exchange agreements and telecommunication contracts. At December 31, 2003, the future minimum payments related to other commitments were as follows:

	(in millions)
2004	\$126
2005	48
2006	30
2007	15
2008	14
Thereafter	5
Total	\$238

Financing Commitments

The Utility's current commitments under financing arrangements include obligations to repay mortgage bonds, senior notes, medium-term notes, pollution control bond-related agreements, deferrable interest subordinated debentures, lines of credit, reimbursement agreements associated with letters of credit, floating rate notes and commercial paper, substantially all of which are pre-petition obligations. On the effective date of the Plan of Reorganization, the Utility expects to reinstate certain pollution control bond-related obligations in the amount of approximately \$814 million. The balance of the pre-petition obligations will be paid in full in cash, plus applicable interest, on or as soon as practicable after the effective date of the Plan of Reorganization. After the effective date, the Utility's obligations will also include, in addition to the reinstated pollution control bond-related obligations, the long-term debt issued in connection with the Plan of Reorganization and the revolving credit and accounts receivable facilities implemented on or about the effective date.

In addition, PG&E Funding, LLC must make scheduled payments on its rate reduction bonds. The balance owed on these bonds at December 31, 2003 was approximately \$1.16 billion. 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.

Capital Expenditures

The Utility's investment in plant and equipment totaled approximately \$1.7 billion in 2003, \$1.5 billion in 2002 and \$1.3 billion in 2001.

The following table reflects the Utility's estimated capital expenditures for the next five years. Capital expenditures for which contracts or firm commitments exist have, in addition to being included in the table below, been included in the table above, which details the Utility's contractual obligations and commitments at December 31, 2003.

	(in millions)
2004	\$1,695
2005	1,806
2006	1,569
2007	1,659
2008	1,716

The Utility's significant capital expenditure projects include:

- 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 \$300 million annually over the next five years;
- Replacement of natural gas distribution pipelines expected to total approximately \$375 million over the next five years;
- Substation upgrades and expansion of line capacity of the electricity transmission system expected to average approximately \$260 million annually over the next five years;
- Replacements and upgrades to the Utility's natural gas transportation facilities expected to total approximately \$600 million over the next five years;
- Replacement of turbines and steam generators and other equipment, including additional security measures, at the Utility's Diablo Canyon power plant, replacements and upgrades to the Utility's hydroelectric generation facilities and costs associated with relicensing the Utility's hydroelectric generation facilities expected to average approximately \$180 million annually over the next five years; and
- Investment in common plant, including computers, vehicles, facilities and communications equipment, expected to average approximately \$150 million annually over the next five years.

The Utility anticipates that its capital expenditures in the next five years will be somewhat higher than capital expenditures in recent years. These additional expenditures are necessary to replace aging and obsolete equipment and accommodate anticipated electricity and natural gas load growth. 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.

The discussion above does not include any capital expenditures for new generation facilities. The 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 also does not include any capital expenditures necessary to implement advanced metering improvements.

Contingencies

Surcharge Revenues

In January 2001, the CPUC authorized increases in electricity rates of \$0.01 per kWh, in March 2001 of another \$0.03 per kWh and in May 2001 of an additional \$0.005 per kWh. The use of these surcharge revenues was restricted to "ongoing procurement costs" and "future power purchases." In November and December 2002, the CPUC approved decisions modifying the restrictions on the use of revenues generated by the surcharges and authorizing the surcharges to be used to restore the Utility's financial health by permitting the Utility to record amounts related to the surcharge revenues as an offset to unrecovered transition costs. From January 2001 to December 31, 2003, the Utility recognized total surcharge revenues of approximately \$8.1 billion, pre-tax. The rate design settlement includes a refund of approximately \$125 million of surcharge revenues. Accordingly, at

December 31, 2003, the Utility has recorded a regulatory liability for the potential refund of approximately \$125 million of surcharge revenues collected during 2003. In addition, if the CPUC requires the Utility to refund any amounts in excess of approximately \$125 million, the Utility's earnings could be materially adversely affected.

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 a statewide pilot program is in progress to test whether and how much residential and small commercial customers will respond to demand responsive rates. If the CPUC determines that it would be cost-effective to install advanced metering on a large-scale and orders 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 (in 2003 dollars), based on a five-year installation schedule starting in 2005.

El Paso Settlement

In June 2003, the Utility, along with a number of other parties, entered into the El Paso settlement, which resolves all potential and alleged causes of action against El Paso for its part in alleged manipulation of natural gas and electricity commodity and transportation markets during the period from September 1996 to March 2003. Under the El Paso settlement, El Paso will pay \$1.5 billion in cash and non-cash consideration, of which approximately \$550 million is now in an escrow account and approximately \$875 million will be paid over 15 to 20 years. The Utility's share of the \$1.5 billion settlement is approximately \$300 million. El Paso also agreed to a \$125 million reduction in El Paso's long-term electricity supply contracts with the DWR, to provide pipeline capacity to California and to ensure specific reserve capacity for the Utility, if needed. In October 2003, the CPUC approved an allocation of these refunds, under which the Utility's natural gas customers would receive approximately \$80 million and its electricity customers would receive approximately \$216 million. The settlement was approved by the FERC in November 2003 and by the San Diego Superior Court in December 2003. At least one appeal of the San Diego Superior Court's approval has been filed; however, the Utility believes that it is probable that the El Paso settlement will not be overturned on appeal. The Utility's proposed electricity rate reduction in 2004, filed with the CPUC on January 26, 2004, included a reduction of \$79 million to the \$2.21 billion after-tax regulatory asset related to this El Paso settlement. In December 2003, the Utility also proposed a gas rate reduction related to this El Paso settlement of \$29 million to be implemented in 2004.

Enron Settlement

On December 23, 2003, the Utility entered into a settlement agreement with five subsidiaries of Enron Corporation, or Enron, settling certain claims between the Utility and Enron, or the Enron settlement. The Enron settlement will become effective if approved by the bankruptcy courts overseeing both the Utility's and Enron's Chapter 11 proceedings. A hearing for approval of the Enron settlement is currently scheduled in the Utility's Chapter 11 proceeding on March 5, 2004. A hearing was held in the Enron bankruptcy court on February 5, 2004 and the matter was submitted. If the Enron settlement is approved, the Utility will receive an after-tax credit of approximately \$90 million that will reduce the \$2.21 billion after-tax regulatory asset as called for in the Settlement Agreement. In its January 26, 2004 filing with the CPUC proposing an electricity rate reduction, the Utility has reduced the revenue requirement related to the \$2.21 billion after-tax regulatory asset to reflect this after-tax credit.

DWR Contracts

The DWR provided approximately 30% of the electricity delivered to the Utility's customers for the year ended December 31, 2003. The DWR purchased the electricity under contracts with various generators and through open market purchases. 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. The DWR remains legally and financially responsible for the electricity procurement contracts.

The 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.

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.

REGULATORY MATTERS

The Utility is regulated primarily by the CPUC and the FERC. The FERC is an independent agency within the U.S. Department of Energy, or DOE, that, among other things, regulates the transmission of electricity and the sale for resale of electricity in interstate commerce. The CPUC has jurisdiction to, among other things, 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.

Rates

Transition from Frozen Rates to Cost of Service Ratemaking

Frozen electricity rates, which began on January 1, 1998, were designed to allow the Utility to recover its authorized utility costs and to the extent frozen rates generated revenues in excess of these costs, to recover the Utility's transition costs. Although the surcharges implemented in 2001 effectively increased the actual rate under the frozen rate structure, increases in the Utility's authorized revenue requirements did not increase the Utility's revenues. In addition, DWR revenue requirements reduced the Utility's revenues under the frozen rate structure. As a result of revised electricity rates discussed below and a January 2004 CPUC decision determining that the rate freeze ended on January 18, 2001, the Utility expects that once approved by the CPUC, its rates will reflect cost of service whereby the Utility's rates are calculated based on the aggregate of various authorized rate components. Changes in any individual revenue requirement will change customers' electricity rates.

On January 26, 2004, the Utility filed revised electricity rates with the CPUC to implement the rate changes based on the Utility's 2004 forecast revenue requirements. These rates reflect allocation of the Utility's revenue requirements in accordance with the rate design settlement entered into with a number of consumer groups and government agencies, including TURN and the CPUC's Office of Ratepayer Advocates, or ORA. The rate design settlement agreement has been submitted to the CPUC for approval. The revised rates and forecast revenue requirements are based on, and ultimately will be adjusted to reflect, pending or final CPUC decisions including:

- The Utility's 2003 GRC;
- The allocation of the DWR's 2004 revenue requirements;
- Pending energy supplier refunds, claim offsets or other credits pursuant to the Settlement Agreement; and
- The calculation of any over-collection of the surcharge revenues for 2003.

Based on the revised revenues filed by the Utility on January 26, 2004, current electricity revenues are expected to be reduced by approximately \$860 million as compared to revenues generated at current rates. On February 11,

2004, a proposed decision was issued which, if ultimately approved by the CPUC, instead is expected to reduce the Utility's current electricity revenues by \$799 million. The most significant portion of the difference between the \$799 million included in the proposed decision and the \$860 million filed by the Utility relates to a proposed decrease in the DWR's revenue requirement included in the Utility's January 26, 2004 rate filing. In the January 26, 2004 rate filing, the Utility had estimated that the DWR's revenue requirement would be reduced by approximately \$79 million related to the DWR's share of the El Paso settlement. However, the DWR protested the Utility's rate filing, indicating that the amount of its share of the El Paso settlement was unknown and that the DWR had not changed its revenue requirement as a result of the El Paso settlement.

The February 11, 2004 proposed decision orders the Utility to amend its January 26, 2004 filing containing the revised electricity rates before March 1, 2004. The CPUC is expected to consider the rate design settlement at its meeting on February 26, 2004. If approved, the new rates are intended to be effective March 1, 2004 or shortly thereafter, and the revenue reduction will be retroactive to January 1, 2004. The Utility believes it is probable that the CPUC will approve this electricity rate reduction and resulting revenue reduction in 2004.

2003 General Rate Case

The CPUC determines the amount of authorized base revenues the Utility can collect from customers to recover its basic business and operational costs for electricity and natural gas distribution operations and for electricity generation operations in a GRC. The Utility's last GRC was its 1999 GRC, approved by the CPUC in 2000. The 2003 GRC has been filed, testimony has been given before the CPUC and the Utility is awaiting a final decision. Any revenue requirement change resulting from a final decision will be retroactive to January 1, 2003.

In July 2003, the Utility and various intervenors (ORA, TURN, Aglet Consumer Alliance, and the City and County of San Francisco) filed a joint motion with the CPUC seeking approval of a settlement agreement resolving specific issues related to the cost of operating the Utility's electricity generation facilities, or the generation settlement. In September 2003, the Utility and various intervenors (ORA, TURN, Aglet Consumer Alliance, the Modesto Irrigation District, the Natural Resources Defense Council and the Agricultural Energy Consumers Association) filed a joint motion with the CPUC seeking approval of the GRC settlement. The GRC settlement, together with the generation settlement, resolves all disputed economic issues among the settling parties related to the Utility's electricity distribution, natural gas distribution and generation revenue requirements, with the exception of the Utility's request that the CPUC include the costs of a pension contribution in the Utility's revenue requirement. The CPUC will resolve the pension contribution issue, as well as other issues raised by non-settling intervenors, in its final decision. The CPUC agreed in the Settlement Agreement to act promptly on the 2003 GRC.

The GRC settlement would result in a total 2003 revenue requirement of approximately \$2.5 billion for electricity distribution operations, representing an increase of approximately \$236 million in the Utility's electricity distribution revenue requirement over the current authorized amount. The GRC settlement provides that the electricity distribution rate base on which the Utility would be entitled to earn an authorized rate of return would be approximately \$7.7 billion, based on recorded 2002 plant, and including net weighted average capital additions for 2003 of approximately \$292 million.

The GRC settlement also would result in a total 2003 revenue requirement of approximately \$927 million for the Utility's natural gas distribution operations, representing an increase of approximately \$52 million in the Utility's natural gas distribution revenue requirement over the current authorized amount. The GRC settlement also provides that the amount of natural gas distribution rate base on which the Utility would be entitled to earn an authorized rate of return would be approximately \$2.1 billion, based on recorded 2002 plant and including weighted average capital additions for 2003 of approximately \$89 million.

Together with the generation settlement, the GRC settlement would result in a 2003 generation revenue requirement of \$912 million, representing an increase of approximately \$38 million in the Utility's generation revenue requirement over the current authorized amount. This generation revenue requirement excludes fuel expense, the cost of electricity purchases, the DWR revenue requirements and nuclear decommissioning revenue requirements. Under the Settlement Agreement, the Utility's adopted 2003 generation rate base of approximately \$1.6 billion would be deemed just and reasonable by the CPUC and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. This reaffirmation of the Utility's electricity generation rate base would allow recognition of an after-tax regulatory asset of approximately \$800 million (or approximately \$1.3 billion pre-tax) as estimated at December 31, 2003. The Utility expects to record this regulatory asset when it meets the probability requirements for regulatory recovery in rates as provided for in SFAS No. 71, "Accounting for the Effects of

Certain Types of Regulation,” or SFAS No. 71. The individual components of the regulatory asset will be amortized over their respective lives. The weighted average life of these individual components is approximately 16 years.

The GRC settlement also provides for new balancing accounts to be established retroactive to January 1, 2004 that permit the Utility to recover its authorized electricity distribution and generation revenue requirement regardless of the level of sales. If sales levels do not generate the full revenue requirement in a period, rates in subsequent periods will be increased to collect the shortfall. Similarly, future rates will decrease if sales levels generate more than the full revenue requirement.

If the Utility prevails on the pension contribution issue, an additional revenue requirement of approximately \$75 million would be allocated among electricity distribution, natural gas distribution and electricity generation operations.

Because the CPUC has yet to issue a final decision on the Utility’s 2003 GRC, the Utility has not included the natural gas distribution revenue requirement increase in its 2003 results of operations. If the CPUC approves a 2003 revenue requirement increase in 2004, the Utility would record both the 2003 and 2004 natural gas distribution revenue requirement increase in its 2004 results of operations.

In 2003 the Utility collected electricity revenue and surcharges subject to refund under the frozen rate structure. The amount of electricity revenue subject to refund pursuant to the rate design settlement in 2003 was \$125 million, which incorporates the impact of the electric portion of the GRC settlement. The Utility has recorded a regulatory liability for such amount. If the revenue requirement that is ultimately approved in the Utility’s 2003 GRC is lower than the amounts described above, the regulatory liability would increase.

The CPUC also is considering a proposed reliability performance incentive mechanism for the Utility that would be in effect from 2004 through 2009. Under the proposed incentive mechanism, the Utility would receive up to \$27 million in additional annual revenues to be recorded in a one-way balancing account to be spent exclusively on reliability performance activities with a goal of decreasing the duration and frequency of electricity outages. The Utility would be entitled to earn a maximum reward of up to \$42 million each year depending on the extent to which the Utility exceeded the reliability performance improvement targets. Conversely, the Utility would be required to pay a penalty of up to \$42 million a year depending on the extent to which it failed to meet the target.

On February 3, 2004, the CPUC reopened the GRC record for the purpose of taking further evidence regarding executive compensation and bonuses. The Utility has filed a report addressing these issues with the CPUC. PG&E Corporation and the Utility are uncertain how this matter will be resolved and when a final GRC decision will be issued.

If the GRC settlement is not approved by the CPUC, the Utility’s ability to earn its authorized rate of return for the years until the next GRC would be adversely affected. The parties to the GRC settlement have agreed that the Utility’s next GRC will determine rates for test year 2007. The Utility is unable to predict the outcome of the 2003 GRC or the impact it will have on its financial condition or results of operations.

Attrition Rate Adjustments for 2004-2006

The GRC settlement provides for yearly adjustments to the Utility’s base revenues, or attrition increases, for the years 2004, 2005 and 2006. The attrition increase will be based upon the change in the consumer price index, or CPI, subject to certain minimums and maximums.

The following tables show the multiplier, and the minimum and maximum percentage change for each revenue requirement along with estimates of the minimum and maximum total electricity distribution, natural gas distribution and generation revenue requirements for the years that would be covered by the 2003 GRC.

	2004	2005	2006
Minimum	2.00% Distribution 1.50% Generation	2.25% Distribution 1.50% Generation	3.00% Distribution 2.50% Generation
Multiplier	Change in CPI	Change in CPI	Change in CPI + 1%
Maximum	3.00% Distribution 3.00% Generation	3.25% Distribution 3.00% Generation	4.00% Distribution 4.00% Generation

	2003	2004	2005	2006
(in billions)				
Electric Distribution Revenues	\$2.493			
Minimum		\$2.543	\$2.600	\$2.678
Maximum		2.568	2.651	2.757
Gas Distribution Revenues	0.927			
Minimum		0.946	0.967	0.996
Maximum		0.955	0.986	1.025
Generation Revenues ⁽¹⁾	0.912			
Minimum		0.926	0.940	0.963
Maximum		0.939	0.968	1.006

(1) Generation calculations exclude an approximately \$32 million incremental attrition adjustment in 2004 to reflect the need for a second refueling outage at the Diablo Canyon power plant during that year.

Because these attrition adjustments are based on the Utility's current authorized capital structure and rate of return, they could be affected by future cost of capital proceedings. In addition, if the Utility prevails on the pension contribution issue as discussed above, the attrition adjustments would be slightly higher to reflect the addition of approximately \$75 million to the Utility's 2003 revenue requirements.

Cost of Capital Proceedings

Each year the Utility must file an application with the CPUC to determine the Utility's authorized capital structure and the authorized rate of return the Utility may earn on its electricity and natural gas distribution and electricity generation assets. For its electricity and natural gas distribution operations and electricity generation operations, the Utility's currently authorized return on equity is 11.22% and its currently authorized cost of debt is 7.57%. The Utility's currently authorized capital structure is 48.00% common equity, 46.20% long-term debt and 5.80% preferred equity.

The Utility must file a cost of capital application within 30 days after completing the financings to implement the Plan of Reorganization. For 2004, this cost of capital proceeding will also determine the authorized rate of return for natural gas transportation and storage. The application must reflect changes in capital structure, long-term debt and preferred stock costs, and costs associated with interest rate hedges. The Settlement Agreement provides that 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 will be no less than 52%. However, for 2004 and 2005, the Utility's authorized equity ratio will equal the greater of the proportion of equity approved in the Utility's 2004 and 2005 cost of capital proceedings and 48.6%.

DWR Revenue Requirements

The DWR filed a proposed \$4.5 billion 2004 power charge revenue requirement and a proposed 2004 bond charge revenue requirement of approximately \$873 million with the CPUC in September 2003. In January 2004, the CPUC issued a decision that adopted an interim allocation of the DWR's proposed 2004 revenue requirements among the three California investor-owned electric utilities. The Utility customers' share of the DWR power charge revenue requirement is approximately \$1.8 billion after consideration of the DWR 2001-2002 adjustment discussed below. The January 2004 decision allocated the bond charge revenue requirement among the three California investor-owned electric utilities on an equal cents per kWh basis, which resulted in approximately \$369 million being allocated to the Utility's customers.

The CPUC will consider adopting a multi-year allocation of the DWR's power charge revenue requirements in a second phase of the 2004 DWR power charge proceeding. If adopted, a multi-year allocation would replace the interim allocation for 2004. The Utility cannot predict the final outcome of this matter.

The DWR revenue requirements have been subject to various adjustments, including the reallocation of contracts among the California investor-owned electric utilities, adjustments to reflect actual deliveries and adjustments resulting from changes in allocation methodologies. In January 2004, the CPUC issued a decision finding that the Utility had over-remitted approximately \$101 million in power charges to the DWR related to the DWR's 2001-2002

revenue requirement and ordered that the Utility's allocation of the DWR's 2004 power charge revenue requirement be reduced by this amount.

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, including the reduction in the 2004 revenue requirement related to 2001 through 2002, will not affect the Utility's results of operations.

Baseline Allowance Increase

In May 2002, the CPUC ordered the California investor-owned electric utilities to increase the baseline allowances for certain residential customers, which reduced the Utility's electricity revenues. An increase to a customer's baseline allowance is an increase to the amount of monthly usage that is covered under the lowest possible electricity rate and exempt from certain surcharges. The CPUC deferred consideration of corresponding rate changes until a later phase of the proceeding and ordered the California investor-owned electricity utilities to track the under-collections associated with their respective baseline quantity changes in an interest-bearing balancing account. The Utility is charging the electricity revenue-related shortfall against earnings because it cannot predict the outcome of the later phase of the proceeding, nor can it conclude that recovery of the electric-related balancing account is probable. The total electricity revenue shortfall was approximately \$70 million for the period from May through December 2002 and approximately \$114 million for 2003.

Proposals have been made that include demographic revisions to baseline allowances, special allowances and changes to baseline territories or seasons that could range to up to an additional \$55 million per year, plus \$6 million in administration costs spread out over three to five years. However, a proposed decision issued by the CPUC in October 2003 would result in annual electric shortfalls of only \$16 million, plus \$2 million in initial administrative costs. The Utility will continue to charge any electricity revenue shortfalls to earnings until the CPUC implements the necessary recovery charges. The proposed decision adopting the rate design settlement if approved by the CPUC would provide for timely rate adjustments for prospective revenue shortfalls resulting from increased baseline allowances. The rate design settlement does not, however, provide for the recovery of shortfalls prior to the implementation of the rate design settlement.

Electricity Procurement

Utility Electricity Procurement

Beginning January 1, 2003, the Utility resumed responsibility for procuring electricity for its residual net open position. The Utility's residual net open position is expected to grow over time for a number of reasons, including:

- Periodic expirations of existing electricity purchase contracts;
- Periodic expirations or other terminations of the DWR allocated contracts. For the period 2004-2009, the DWR must-take contracts and contracts with mandatory capacity payments are expected to supply about 25% of the electricity demands of the Utility's customers. For the period 2010-2012, the DWR must-take contracts and contracts with mandatory capacity payments are expected to supply less than 10% of the electricity demands of the Utility's customers;
- Increases in the Utility's customers' electricity demands due to customer and economic growth or other factors; and
- Retirement or closure of the Utility's electricity generation facilities.

In addition, unexpected outages at the Utility's Diablo Canyon power plant, or any of the Utility's other significant 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.

In January 2004, the CPUC adopted an interim decision that would require the California investor-owned electric utilities to achieve by January 1, 2008 an electricity reserve margin of 15-17% in excess of peak capacity electricity requirements and have a diverse portfolio of electricity sources. These requirements may increase the Utility's residual net open position. Specific procedures contained in the decision relating to development and execution of the Utility's procurement plans may also cause the cost of electricity to the Utility to increase.

Effective January 1, 2003, under 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 recorded 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. 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 aggregate over-collections or under-collections exceed 5% of the utility's prior year electricity procurement revenues, excluding amounts collected for the DWR. These mandatory adjustments will continue until January 1, 2006. The CPUC's review of the Utility's procurement activities will examine the Utility's least-cost dispatch of its resource portfolio including the DWR allocated contracts, fuel expenses for the Utility's electricity generation facilities, contract administration (including administration of the DWR allocated contracts) and the Utility's electricity procurement contracts. As a result of this review, some of the Utility's procurement costs could be disallowed. The Utility cannot predict whether a disallowance will occur or the size of any potential disallowance.

In February 2004, the Utility requested that the CPUC approve the Utility's 2004 ERRRA revenue requirement of approximately \$2.2 billion associated with the Utility's 2004 short-term procurement plan. Costs associated with electricity procurement contracts entered into prior to January 1, 2003, such as the qualifying facility contracts, are eligible for recovery under the ERRRA provided the costs are under a CPUC authorized benchmark. The benchmark anticipated to be adopted by the CPUC for 2004 is \$0.0518 per kWh, based upon a report prepared by the California Energy Commission. The CPUC will establish a benchmark for each year of the ERRRA. Determination of whether procurement costs associated with these contracts are within the benchmark is done on a portfolio basis including a hypothetical cost for the Utility's own generation facilities. Costs that are above the benchmark are recoverable as above-market generation and procurement costs. The Utility has asked the CPUC to approve an additional proposed revenue requirement of approximately \$150 million to recover the 2004 costs related to the above-market generation and procurement costs that exceed the CPUC-adopted benchmark discussed above.

On January 26, 2004, the Utility filed with the CPUC revised electricity rates to implement rate changes based on the Utility's overall revenue requirements for 2004. If this filing and related filings are approved, the ERRRA would track and allow recovery of the difference between actual ERRRA revenues collected and actual costs incurred.

Although the CPUC has no authority to review the reasonableness of procurement costs in the DWR's contracts, it may review the Utility's administration of the DWR allocated contracts. The Utility is required to dispatch its electricity resources, including the DWR allocated contracts, on a least-cost basis. The CPUC has established a maximum annual procurement disallowance for the Utility's administration of the DWR allocated contracts and least-cost dispatch of its electricity resources of two times the Utility's administration costs of managing procurement activities, or \$36 million for 2003. Activities excluded from the maximum annual disallowance include fuel expenses for the Utility's electricity generation resources and contract administration costs associated with electricity procurement contracts, qualifying facility contracts and certain electricity generation expenses. In its decision approving the Utility's 2004 short-term procurement plan, the CPUC extended the application of this maximum disallowance amount to cover the Utility's 2004 procurement activities. It is uncertain whether the CPUC will modify or eliminate the maximum annual disallowance for future years.

FERC Prospective Price Mitigation Relief

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 January 2000 to June 2001. In December 2002, a FERC administrative law judge issued an initial decision 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 (the only time period for which the FERC permitted refund claims), but that California buyers still owe the power suppliers approximately \$3.0 billion, leaving approximately \$1.2 billion in net unpaid bills.

During 2003, the FERC confirmed most of the administrative law judge's findings, 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 has indicated that it plans to make its compliance filing by August 2004. The actual refunds will not be determined until the FERC issues a final decision following the ISO and PX compliance filings. The FERC is uncertain when it will issue a final decision in this proceeding. In addition, future refunds could increase or decrease as a result of an alternative calculation proposed by the ISO, which incorporates revised data provided by the Utility and other entities.

Under the Settlement Agreement, the Utility and PG&E Corporation agreed to continue to cooperate with the CPUC and the State of California in seeking refunds from generators and other energy suppliers. The net after-tax amount of any refunds, claim offsets or other credits from generators or other energy suppliers relating to the Utility's ISO, PX, qualifying facilities or energy service provider costs that are actually realized in cash or by offset of creditor claims in its Chapter 11 proceeding would reduce the balance of the \$2.21 billion after-tax regulatory asset created by the Settlement Agreement.

The Utility has 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. The Utility currently estimates that the claims filed would have been reduced to approximately \$1.2 billion based on the refund methodology recommended in the administrative law judge's initial decision, resulting in a net liability of approximately \$1.0 billion after the approximately \$200 million pre-petition offset. The recalculation of market prices according to the revised methodology adopted by the FERC in its October 2003 decision could further reduce the amount of the suppliers' claims by several hundred million dollars. However, 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.

FERC Transmission Rate Cases

On January 13, 2003, the Utility filed an application with the FERC requesting authority to recover approximately \$545 million in annual electricity transmission retail revenue requirements for 2003. The January 13, 2003 proposed rates went into effect, subject to refund, on August 13, 2003 and remained in effect through December 31, 2003. The Utility has accrued approximately \$26 million for potential refunds related to the period these rates were in effect.

The Utility filed an additional rate application with the FERC at the end of October 2003 requesting recovery of approximately \$530 million per year, subject to refund, in electricity transmission retail revenue requirements. The Utility requested a 13.0% return on equity and recovery of the costs of providing safe and reliable transmission service during 2004. On December 30, 2003 the FERC accepted this proposed revenue requirement and related rates, subject to hearing and refund, effective as of January 1, 2004.

Natural Gas Supply and Transportation

In 1998, the Utility implemented a ratemaking pact called 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. On December 18, 2003, the CPUC approved the Utility's application to retain the Gas Accord market structure for 2004 and 2005 and resolved the rates, and terms and conditions of service for the Utility's natural gas transportation and storage system for 2004. The CPUC adopted a 2004 revenue requirement of \$436.4 million, representing a \$12.5 million increase from 2003.

In addition, the December 2003 CPUC decision exempts, beginning in 2005, certain customers connected to the Utility's backbone transportation facilities from paying local transportation rates and orders the Utility to review and consider a backbone level rate structure, which may include a surcharge to recover what may otherwise be stranded costs resulting from departing local transmission customers. The Utility's backbone transportation facilities connect natural gas transportation pipelines delivering natural gas from California's border and from California production and storage facilities to the local natural gas transportation system.

Under the Gas Accord market structure, the Utility is at risk of not recovering its natural gas transportation and storage costs and does not have regulatory balancing account provisions for over-collections or under-collections of natural gas transportation or storage revenues. The Utility may experience a material reduction in operating revenues if throughput levels or market conditions are significantly less favorable than reflected in rates for these services.

The Gas Accord also established 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. The December 2003 CPUC decision extended the CPIM with adjustments through 2005. Under the CPIM, the Utility's purchase costs 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 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.

On January 22, 2004 the CPUC opened a rulemaking to require California natural gas utilities to submit proposals aimed at ensuring reliable, long-term supplies of natural gas to California. 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. This proceeding will be divided into two phases. Phase 1 will address utilities' expiring contracts with interstate pipelines, the amount of interstate capacity the utilities should hold, the approval process for contracts with interstate pipelines and access to liquefied natural gas facilities supplies. Phase 2 will examine broader long-term supply and capacity issues. The Utility is unable to predict the outcome of this rulemaking or the impact it will have on its financial condition or results of operations.

Annual Earnings Assessment Proceeding for Energy Efficiency Program Activities and Public Purpose Programs

In May 2003, 2002, 2001 and 2000, the Utility filed its annual applications with the CPUC claiming incentives totaling approximately \$106 million in the Annual Earnings Assessment Proceeding for energy efficiency program activities and public purpose programs. These applications remain subject to verification and approval by the CPUC. The CPUC has only authorized the Utility to recognize an insignificant amount of these incentives in its consolidated statements of operations. There are a number of forward-looking proceedings regarding program administration and incentive mechanisms for energy efficiency. It is too early to predict whether the CPUC will allow the Utility to continue administering energy efficiency programs and earning incentives based on the performance of the programs.

2001 Annual Transition Cost Proceeding: Review of Reasonableness of Electricity Procurement

In April 2003, the ORA issued a report regarding the Utility's procurement activities for the period July 1, 2000 through June 30, 2001, recommending that the CPUC disallow recovery of approximately \$434 million of the Utility's procurement costs based on an allegation that the Utility's market purchases during the period were imprudent because they did not develop and execute a reasonable hedging strategy. The ORA recommendation does not take into account any FERC-ordered refunds of the Utility's procurement costs during this period, which could effectively reduce the amount of the recommended disallowance. In the Utility's response to the ORA's report, the Utility indicated that the ORA recommendation is unlawful, contrary to prior CPUC decisions, and factually unsupported. Under the Settlement Agreement, the CPUC would agree to act promptly to resolve this proceeding, with no adverse impact on the Utility's cost recovery, as soon as practicable after the Plan of Reorganization becomes effective.

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 with 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, reduce earnings volatility and manage cash flows. The Utility's risk management activities often include the use of energy and financial derivative instruments, including forward contracts, futures, swaps, options, and other instruments and agreements.

The Utility uses derivative instruments only for non-trading purposes (*i.e.* , risk mitigation) and not for speculative purposes. The Utility uses derivative instruments to mitigate the risks associated with ownership of assets, liabilities, committed transactions or probable forecasted transactions. The Utility enters into derivative instruments in accordance with approved risk management policies adopted by a risk oversight committee composed of senior officers and only after the risk oversight committee approves appropriate risk limits for each derivative instrument. The organizational unit proposing the activity must successfully demonstrate that the derivative instrument satisfies a business need and that the attendant risks will be adequately measured, monitored and controlled.

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.

Because NEGT's financial results are no longer consolidated with those of PG&E Corporation, NEGT's market risks do not impact PG&E Corporation's net income and cash flows.

Price Risk

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. On January 1, 2003, the Utility resumed responsibility for purchasing electricity to meet its residual net open position. The Utility has purchased electricity on the spot market and the short-term forward market (contracts with delivery times ranging from one hour ahead to one year ahead) since that date.

It is estimated that the residual net open position will increase over time for a number of reasons, including:

- Periodic expirations of existing electricity purchase contracts;
- Periodic expirations or other terminations of the DWR allocated contracts;
- Increases in the Utility's customers' electricity demands due to customer and economic growth or other factors; and
- Retirement or closure of the Utility's generation facilities.

In addition, unexpected outages at the Utility's Diablo Canyon power plant or any of the Utility's other significant 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.

The Settlement Agreement contemplates 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 that do not comply with the CPUC-approved short-term procurement plan. Additionally, adverse 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 agreements are with large, well-established international producers for its long-term nuclear fuel agreements in order to diversify its commitments and ensure security of supply.

Nuclear fuel purchases are subject to tariffs of up to 50% 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, once these contracts begin to expire in 2004, the costs under new nuclear fuel contracts may increase. While the cost recovery regulatory mechanisms under California law described above remain in place, adverse market changes in nuclear fuel prices are not expected to materially impact net income.

Natural Gas

The Utility enters into physical and financial natural gas commodity contracts of up to one-and-a-half years 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 must be purchased in the spot market. To mitigate the risk of price volatility, the Utility enters into various financial instruments, including options that may extend for up to five months in length. The Utility's cost of natural gas includes the cost of Canadian and interstate transportation of natural gas purchased for its core customers.

Under the CPIM, the Utility's purchase costs 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 three-fourths of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark, in their rates. 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 risk for the portion of intrastate natural gas transportation capacity that is not 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 a value-at-risk methodology to measure the expected maximum daily change in the 18-month forward value of its transportation and storage portfolio. The value-at-risk provides an indication of the Utility's exposure to potential high-risk market conditions, and market opportunities for improved revenues based on price changes, high-price volatility or correlation between pricing locations. It is also an important indicator of the effectiveness of hedge strategies on a portfolio. The value-at-risk methodology is based on a 95% confidence level, which means that there is a 5% probability that the portfolio will incur a loss in value in one day at least as large as the reported value-at-risk. The one-day liquidation period assumption of the value-at-risk methodology does not match the longer-term holding period of the Utility's transportation and storage contract portfolio.

The Utility's value-at-risk for its transportation and storage portfolio was approximately \$4.2 million at December 31, 2003 and approximately \$4 million at December 31, 2002. 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 2003 was approximately \$12.8, \$1.7 and \$5.4 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, volumetric risk, inadequate indication of the exposure of a portfolio to extreme price movements and the inability to address the risk resulting from intra-day trading activities.

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, 2003, 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.

As discussed above the Utility plans to issue long-term debt and establish credit facilities to facilitate payment of allowed claims in the Utility's Chapter 11 proceeding. The Utility entered into derivative instruments, which expire in June 2004, to partially hedge the interest rate risk on up to \$7.4 billion of the long-term debt to be issued.

The hedges are reflected on the balance sheet at fair value in other current assets. The cost of the hedges, purchased at fair value, was approximately \$45 million. The fair value of the hedges at December 31, 2003 was approximately \$17 million. At December 31, 2003, a hypothetical 1% decrease in interest rates would cause the fair value of the interest rate hedges to fall below \$1 million; however, the change in fair value of the interest rate hedges would primarily be reported in regulatory accounts, and would be offset by changes in interest expense once the forecasted debt is issued.

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 \$2.5 billion at December 31, 2003 and approximately \$2.0 billion at December 31, 2002. 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 \$68 million at December 31, 2003 and approximately \$59 million at December 31, 2002 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 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 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 largest 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 2003, the Utility recognized no material losses due to contract defaults or bankruptcies. At December 31, 2003, there were three counterparties that represented greater than 10% of the Utility's net credit exposure. The Utility had two investment grade counterparties that represented a total of approximately 32% of the Utility's net credit exposure and one below-investment grade counterparty that represented approximately 12% of the Utility's net credit exposure.

The Utility conducts business with customers or vendors 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.

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.

DWR Revenues

The Utility acts as a pass-through entity for electricity purchased by the DWR that is sold to the Utility's customers. Although charges for electricity provided by the DWR are included in the amounts the Utility bills its customers, the Utility deducts from electricity revenues 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, priced at the related CPUC-approved remittance rate. These pass-through amounts are excluded from the Utility's electricity revenues in its Consolidated Statements of Operations. During 2003, 2002 and 2001, the pass-through amounts have been subject to significant adjustments.

On January 26, 2004, the Utility filed with the CPUC revised electricity rates to implement all rate changes based on the Utility's overall revenue requirements for 2004. If approved, the new rates will be effective March 1,

2004, and the resultant revenue reduction will be retroactive to January 1, 2004. Because the DWR's revenue requirements will be included as a component of the Utility's total rates in 2004, these DWR revenue requirements, and any related adjustments, will result in adjustment to the Utility's electricity rates and are not expected to impact the Utility's future results of operations or financial position.

The DWR's revenue requirements are subject to various adjustments, including the reallocation of DWR contracts among the California investor-owned electric utilities, adjustments to actual deliveries and changes in allocation methodologies. In January 2004, the CPUC issued a decision finding that the Utility over-remitted approximately \$101 million in power charges to the DWR related to the DWR's 2001-2002 revenue requirement and ordered that the Utility's allocation of the DWR's 2004 revenue requirement to the customers of the California investor-owned electric utilities be reduced by this amount.

Regulatory Assets and Liabilities

PG&E Corporation and the Utility apply SFAS No. 71 to their regulated 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 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, 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 are recorded and that can be recovered through rates.

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, 2003 PG&E Corporation reported regulatory assets (including current regulatory balancing accounts receivable) of approximately \$2.2 billion and regulatory liabilities (including current balancing accounts payable) of approximately \$4.2 billion.

The Utility expects to recognize the regulatory assets created by the Settlement Agreement when they meet the probability requirements of SFAS No. 71. Implementation of the Plan of Reorganization is subject to various conditions, including the consummation of the public offering of long-term debt, the receipt of investment grade credit ratings and final CPUC approval of the Settlement Agreement. Under the terms of the Plan of Reorganization PG&E Corporation and the Utility may determine that the CPUC order approving the Settlement Agreement is final even if appeals are pending. There can be no assurance that the Settlement Agreement will not be modified on rehearing or appeal or that the Plan of Reorganization will become effective. Until certain conditions or events regarding the effectiveness of the Plan of Reorganization discussed above are resolved further, the Utility cannot conclude that it has met the probability requirements of SFAS No. 71 and therefore cannot record the regulatory assets contemplated in the Settlement Agreement.

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.

Surcharge Revenues

In January 2001, the CPUC authorized increases in electricity rates of \$0.01 per kWh, in March 2001 of another \$0.03 per kWh and in May 2001 of an additional \$0.005 per kWh. The use of these surcharge revenues was initially restricted to "ongoing procurement costs" and "future power purchases." In November and December 2002, the CPUC approved decisions modifying the restrictions on the use of revenues generated by the surcharges and authorizing the surcharges to be used to restore the Utility's financial health by permitting the Utility to record amounts related to the surcharge revenues as an offset to unrecovered transition costs. From January 2001 to December 31, 2003, the Utility recognized total surcharge revenues of approximately \$8.1 billion, pre-tax. The rate design settlement includes a refund of approximately \$125 million of surcharge revenues. Accordingly, at December 31, 2003, the Utility has recorded a regulatory liability for the potential refund of approximately \$125 million of surcharge revenues collected during 2003. In addition, if the CPUC requires the Utility to refund any amounts in excess of \$125 million, the Utility's earnings could be materially adversely affected.

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 and its 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, 2003 the Utility's undiscounted environmental liability was approximately \$314 million, which was approximately \$17 million lower than at December 31, 2002, mainly due to a reassessment of the estimated cost of remediation and remediation payments. The Utility's undiscounted future costs could increase to as much as \$422 million if other potentially responsible parties are not able to contribute to the settlement of these costs, the extent of contamination or necessary remediation is greater than anticipated or the Utility is found to be responsible for additional clean-up costs.

Derivatives

In 2001, PG&E Corporation and the Utility adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, or SFAS No. 133, which required all derivative instruments to be recognized in the financial statements at their fair value.

The Utility has long-term purchase contracts, including power purchase and renewable energy, natural gas supply and transportation, and nuclear fuel as reflected in "Capital Expenditures and Commitments" discussed above. The Utility has determined most of these contracts, including substantially all of its qualifying facility and nuclear fuel contracts, are not derivative instruments. Most of the remaining contracts that are derivative instruments are exempt from the mark-to-market requirements of SFAS No. 133 under the normal purchases and sales exception and are not reflected on the balance sheet at fair value. In addition, the Utility holds derivative instruments that are used to offset natural gas commodity price risk and interest rate risk. These instruments qualify for cash flow hedge treatment under SFAS No. 133 and are presented on the balance sheet at fair value, which amounted to approximately \$21 million at December 31, 2003.

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 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 certain actuarial assumptions. 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. 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.

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 8.5%.

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, 2003. 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. For the Utility Retirement Plan, a decrease in the discount rate from 6.25% to 6.00% would increase the accumulated benefit obligation by approximately \$202 million.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003

In January 2004, the Financial Accounting Standards Board, or FASB, issued FASB Staff Position SFAS No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," or SFAS No. 106-1. SFAS No. 106-1 permits a sponsor to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003, or the Prescription Drug Act. The Prescription Drug Act, signed into law in December 2003, establishes a prescription drug benefit under Medicare (Medicare Part D) and a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. SFAS No. 106-1 does not provide specific guidance as to whether a sponsor should recognize the effects of the Prescription Drug Act in its financial statements. The Prescription Drug Act introduces two new features to Medicare that must be considered when measuring accumulated postretirement benefit costs. The new features include a subsidy to the plan sponsors that is based on 28% of an individual beneficiary's annual prescription drug costs between \$250 and \$5,000 and an opportunity for a retiree to obtain a prescription drug benefit under Medicare. The Prescription Drug Act is expected to reduce PG&E Corporation's net postretirement benefit costs.

PG&E Corporation and the Utility have elected to defer adoption of SFAS No. 106-1 due to the lack of specific guidance. Therefore, the net postretirement benefit costs disclosed in PG&E Corporation's and the Utility's Consolidated Financial Statements do not reflect the impacts of the Prescription Drug Act on the plans. The deferral will continue to apply until specific authoritative accounting guidance for the federal subsidy is issued. Authoritative guidance on the accounting for the federal subsidy is pending and, when issued, could require information previously reported in PG&E Corporation's and the Utility's Consolidated Financial Statements to change. PG&E Corporation and the Utility are currently investigating the impacts of SFAS 106-1's initial recognition, measurement and disclosure provisions on their Consolidated Financial Statements.

Change in Accounting for Certain Derivative Contracts

In November 2003 the FASB approved an amendment to an interpretation issued by the Derivatives Implementation Group C15, (as previously amended in October 2001 and December 2001, or DIG C15), that changed the definition of normal purchases and sales for certain power contracts that contain optionality.

The implementation guidance in DIG C15 impacts certain derivative instruments entered into after June 30, 2003. Prior to this amendment to DIG C15, most of the Utility's derivative instruments have qualified for the normal purchases and sales exception. However, it is possible that new derivative instruments and certain of the Utility's derivative instruments entered into prior to July 1, 2003 will no longer qualify for normal purchases and sales treatment under the new guidelines of DIG C15. Application of the new guidance to existing derivative instruments that were eligible for the normal purchases and sales exception under the previous DIG C15 guidance will be effective in the first quarter of 2004 as a cumulative effect of a change in accounting principle. PG&E Corporation and the Utility are currently evaluating the impacts, if any, of DIG C15 on their Consolidated Financial Statements.

Consolidation of Variable Interest Entities

In December 2003, the FASB issued Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities," or FIN 46R, replacing Interpretation No. 46, "Consolidation of Variable Interest Entities," or FIN 46, which was issued in January 2003. FIN 46R was issued to replace FIN 46 and to clarify the required accounting for interests in variable interest entities. A variable interest entity is an entity that does not have sufficient equity investment at risk, or the holders of the equity instruments lack the essential characteristics of a controlling financial interest. A variable interest entity is to be consolidated by a company if that company is subject to a majority of the risk of loss from the variable interest entity's activities, or is entitled to receive a majority of the entity's residual returns, or both.

PG&E Corporation and the Utility must apply the provisions of FIN 46R as of January 1, 2004. PG&E Corporation and the Utility are continuing to evaluate the impacts of FIN 46R's initial recognition, measurement and disclosure provisions on their Consolidated Financial Statements and are unable to estimate the impact, if any, which will result when FIN 46R becomes effective. The Utility has investments in unconsolidated affiliates, which are mainly engaged in the purchase of low-income residential real estate property. It is reasonably possible that the Utility will be required to consolidate its interests in these entities as a result of the adoption of FIN 46R. At December 31, 2003 the Utility's recorded investment in these entities was approximately \$21 million. As a limited partner, the Utility's exposure to potential loss is limited to its investment in each partnership.

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 \$74 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.

The IRS also is auditing PG&E Corporation's 1999 and 2000 consolidated federal income tax returns, but has not issued its final report. In the fourth quarter of 2003, PG&E Corporation made an advance payment to the IRS of \$75 million to halt the accrual of interest in respect of these tax returns. The assessment and payment did not have a material effect on PG&E Corporation's financial position or results of operations.

As a result of NEGT's Chapter 11 filing on July 8, 2003, the IRS recently began its audit of PG&E Corporation's 2001 and 2002 consolidated federal income tax returns. On June 27, 2003 the IRS announced it will review scientific tests related to production of synthetic fuels. A partnership owned by NEGT subsidiaries operated two synthetic fuel facilities in 2001 and most of 2002. PG&E Corporation has claimed tax credits totaling approximately \$104 million for these facilities. If the IRS determines that these synthetic fuel facilities do not meet the criteria to qualify for the tax credit, PG&E Corporation may be subject to additional tax and interest. All of PG&E Corporation's federal income tax returns prior to 1997 have been closed. In addition, California and certain other state tax authorities currently are auditing various state tax returns.

In 2003, PG&E Corporation increased its valuation allowance against certain state deferred tax assets related to NEGT or its subsidiaries due to the uncertainty in their realization. Valuation allowances of approximately \$24 million were recorded in discontinued operations, and approximately \$5 million in accumulated other comprehensive loss for 2003.

PG&E Corporation will not recognize additional income tax benefits for financial statement reporting purposes after July 7, 2003 with respect to any subsequent losses related to NEGT or its subsidiaries even though it continues to include NEGT and its subsidiaries in its consolidated income tax returns. Any such unrecognized benefits and deferred tax assets arising from losses related to NEGT or its subsidiaries that have been recognized through July 7, 2003 will be recorded in discontinued operations in the Consolidated Statements of Operations at the time that PG&E Corporation releases its ownership interest in NEGT.

NEGT and its creditors have brought litigation against PG&E Corporation and two PG&E Corporation officers who previously served on NEGT's Board of Directors, in NEGT's Chapter 11 proceeding, asserting, among other claims, that NEGT is entitled to be compensated under an alleged tax sharing agreement between PG&E Corporation and NEGT for any tax savings achieved by PG&E Corporation as a result of the incorporation of the losses and deductions related to NEGT or its subsidiaries in PG&E Corporation's consolidated federal tax return. This litigation is discussed above.

ADDITIONAL SECURITY MEASURES

The NRC issued orders in 2003 regarding additional security measures for all nuclear plants, including the Utility's Diablo Canyon power plant. These orders require additional capital investment and increased operating costs. However, neither PG&E Corporation nor the Utility believes these costs will have a material impact on its consolidated financial position or results of operation.

PG&E Corporation
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share amounts)

	Year ended December 31,		
	2003	2002	2001
Operating Revenues			
Electric	\$ 7,582	\$ 8,178	\$ 7,326
Natural gas	2,853	2,327	3,124
Total operating revenues	10,435	10,505	10,450
Operating Expenses			
Cost of electricity	2,309	1,447	2,717
Cost of natural gas	1,438	895	1,720
Operating and maintenance	2,963	2,858	2,404
Depreciation, amortization, and decommissioning	1,222	1,196	899
Reorganization professional fees and expenses	160	155	97
Total operating expenses	8,092	6,551	7,837
Operating Income (Loss)	2,343	3,954	2,613
Reorganization interest income	46	71	91
Interest income	16	9	46
Interest expense	(1,147)	(1,224)	(1,078)
Other income (expense), net	(9)	50	(43)
Income Before Income Taxes	1,249	2,860	1,629
Income tax provision	458	1,137	608
Income From Continuing Operations	791	1,723	1,021
Discontinued Operations			
Earnings (Loss) from operations of NEGТ (net of income tax benefit of \$230 million in 2003, \$1,558 million in 2002, and none in 2001)	(365)	(2,536)	69
Net Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	426	(813)	1,090
Cumulative effect of changes in accounting principles of \$(5) million in 2003, \$(61) million in 2002, and \$9 million in 2001 related to discontinued operations (net of income tax expense (benefit) of \$(3) million in 2003, \$(42) million in 2002, and \$6 million in 2001). In 2003, \$(1) million related to continuing operations (net of income tax benefit of \$1 million)	(6)	(61)	9
Net Income (Loss)	\$ 420	\$ (874)	\$ 1,099
Weighted Average Common Shares Outstanding, Basic	385	371	363
Earnings Per Common Share from Continuing Operations, Basic	\$ 2.05	\$ 4.64	\$ 2.81
Net Earnings (Loss) Per Common Share, Basic	\$ 1.09	\$ (2.36)	\$ 3.03
Earnings Per Common Share from Continuing Operations, Diluted	\$ 1.96	\$ 4.50	\$ 2.80
Net Earnings (Loss) Per Common Share, Diluted	\$ 1.06	\$ (2.26)	\$ 3.02

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2003	2002
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 3,658	\$ 3,532
Restricted cash	403	527
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$68 million in 2003 and \$59 million in 2002)	2,424	1,921
Related parties	15	—
Regulatory balancing accounts	248	98
Inventories:		
Gas stored underground	166	154
Materials and supplies	126	121
Current assets of NEGT	—	3,029
Prepaid expenses and other	108	111
Total current assets	7,148	9,493
Property, Plant and Equipment		
Electric	20,468	18,922
Gas	8,355	8,123
Construction work in progress	379	427
Other	20	21
Total property, plant and equipment	29,222	27,493
Accumulated depreciation	(11,115)	(13,528)
Net property, plant and equipment	18,107	13,965
Other Noncurrent Assets		
Regulatory assets	2,001	2,011
Nuclear decommissioning funds	1,478	1,335
Long-term assets of NEGT	—	4,883
Other	1,441	1,373
Total other noncurrent assets	4,920	9,602
TOTAL ASSETS	\$ 30,175	\$ 33,060

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED BALANCE SHEETS
(in millions, except per share amounts)

	Balance at December 31,	
	2003	2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Long-term debt, classified as current	\$ 310	\$ 281
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	657	380
Regulatory balancing accounts	186	364
Other	402	421
Interest payable	174	139
Income taxes payable	256	83
Current liabilities of NEGT	—	6,657
Other	863	658
Total current liabilities	3,138	9,273
Noncurrent Liabilities		
Long-term debt	3,314	3,715
Rate reduction bonds	870	1,160
Regulatory liabilities	3,979	1,461
Asset retirement obligations	1,218	—
Deferred income taxes	856	782
Deferred tax credits	127	144
Net investment in NEGT	1,216	—
Long-term liabilities of NEGT	—	1,907
Preferred stock of subsidiary with mandatory redemption provisions	137	—
Other	1,501	1,323
Total noncurrent liabilities	13,218	10,492
Liabilities Subject to Compromise		
Financing debt	5,603	5,605
Trade creditors	3,715	3,597
Total liabilities subject to compromise	9,318	9,202
Commitments and Contingencies (Notes 1, 2, 5 and 12)	—	—
Preferred Stock of Subsidiaries	286	480
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 414,985,014 common and 1,535,268 restricted shares in 2003 and 405,486,015 common shares in 2002	6,468	6,274
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Unearned compensation	(20)	—
Accumulated deficit	(1,458)	(1,878)
Accumulated other comprehensive loss	(85)	(93)
Total common shareholders' equity	4,215	3,613
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$30,175	\$33,060

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2003	2002	2001
Cash Flows From Operating Activities			
Net income (loss)	\$ 420	\$ (874)	\$ 1,099
Loss (income) from discontinued operations	365	2,536	(69)
Cumulative effect of changes in accounting principles	6	61	(9)
Net income from continuing operations	791	1,723	1,021
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and decommissioning	1,222	1,196	899
Deferred income taxes and tax credits, net	190	(281)	(356)
Reversal of ISO accrual	—	(970)	—
Other deferred charges and noncurrent liabilities	857	921	(857)
Loss from retirement of long-term debt	89	153	—
Gain on sale of assets	(29)	—	—
Net effect of changes in operating assets and liabilities:			
Restricted cash	(237)	(473)	(4)
Accounts receivable	(605)	212	105
Inventories	(17)	62	(57)
Accounts payable	403	198	1,311
Accrued taxes	173	(619)	1,715
Regulatory balancing accounts, net	(329)	(23)	311
Other working capital	(90)	22	574
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(87)	(1,442)	(16)
Other, net	171	135	249
Net cash provided by operating activities	2,502	814	4,895
Cash Flows From Investing Activities			
Capital expenditures	(1,698)	(1,547)	(1,347)
Net proceeds from sale of asset	49	11	—
Other, net	(112)	25	5
Net cash used by investing activities	1,761	(1,511)	(1,342)
Cash Flows From Financing Activities			
Net repayments under credit facilities	—	—	(959)
Long-term debt issued	581	847	907
Long-term debt matured, redeemed, or repurchased	(1,068)	(1,241)	(111)
Rate reduction bonds matured	(290)	(290)	(290)
Common stock issued	166	217	15
Common stock repurchased	—	—	(1)
Dividends paid	—	—	(109)
Other, net	(4)	—	(1)
Net cash used by financing activities	(615)	(467)	(549)
Net change in cash and cash equivalents	126	(1,164)	3,004
Cash and cash equivalents at January 1	3,532	4,696	1,692
Cash and cash equivalents at December 31	\$ 3,658	\$ 3,532	\$ 4,696
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	\$ 39	\$ 75	\$ 87
Cash paid for:			
Interest (net of amounts capitalized)	866	1,414	579
Income taxes paid (refunded), net	(91)	971	(692)

Reorganization professional fees and expenses	99	99	19
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	181	419	11,400

See accompanying Notes to the Consolidated Financial Statements.

PG&E Corporation
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in millions, except share amounts)

	Common stock shares	Common stock	Common stock held by subsidiary	Unearned compensation	Reinvested earnings (accumulated deficit)	Accumulated other compre- hensive income (loss)	Total common share- holders' equity	Comprehensive income (loss)
Balance at December 31, 2000	387,193,727	\$5,971	\$(690)	–	\$(2,105)	\$ (4)	\$3,172	
Net income		–	–	–	1,099	–	1,099	\$1,099
Cumulative effect of adoption of SFAS No. 133 and interpretations (net of income tax benefit of \$86 million)		–	–	–	–	(243)	(243)	(243)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133 (net of income tax expense of \$105 million)		–	–	–	–	237	237	237
Net reclassification to earnings (net of income tax benefit of \$2 million)		–	–	–	–	42	42	42
Foreign currency translation adjustment (net of income tax benefit of \$1 million)		–	–	–	–	(1)	(1)	(1)
Other (net of zero income tax)		–	–	–	–	(1)	(1)	(1)
Comprehensive income				–				\$1,133
Common stock issued	739,158	16	–	–	–	–	16	
Common stock repurchased	(34,037)	(1)	–	–	–	–	(1)	
Other		–	–	–	2	–	2	
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 income				–				\$ (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	

See accompanying Notes to the Consolidated Financial Statements.



Pacific Gas and Electric Company, A Debtor-In-Possession
CONSOLIDATED STATEMENTS OF OPERATIONS
(in millions, except per share amounts)

	Year Ended December 31,		
	2003	2002	2001
Operating Revenues			
Electric	\$ 7,582	\$ 8,178	\$ 7,326
Natural gas	2,856	2,336	3,136
Total operating revenues	10,438	10,514	10,462
Operating Expenses			
Cost of electricity	2,319	1,482	2,774
Cost of natural gas	1,467	954	1,832
Operating and maintenance	2,935	2,817	2,385
Depreciation, amortization and decommissioning	1,218	1,193	896
Reorganization professional fees and expenses	160	155	97
Total operating expenses	8,099	6,601	7,984
Operating Income	2,339	3,913	2,478
Reorganization interest income	46	71	91
Interest income	7	3	32
Interest expense (non-contractual interest expense of \$131 million in 2003, \$149 million in 2002, and \$164 million in 2001)	(953)	(988)	(974)
Other income (expense), net	13	(2)	(16)
Income Before Income Taxes	1,452	2,997	1,611
Income tax provision	528	1,178	596
Net Income Before Cumulative Effect of a Change in Accounting Principle	924	1,819	1,015
Cumulative effect of a change in accounting principle (net of income tax benefit of \$1 million for the year ended December 31, 2003)	(1)	—	—
Net Income	923	1,819	1,015
Preferred stock dividend requirement	22	25	25
Income Available for Common Stock	\$ 901	\$ 1,794	\$ 990

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, A Debtor-In-Possession
CONSOLIDATED BALANCE SHEETS
(in millions)

	Balance at December 31,	
	2003	2002
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 2,979	\$ 3,343
Restricted cash	403	150
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$68 million in 2003 and \$59 million in 2002)	2,424	1,921
Related parties	17	17
Regulatory balancing accounts	248	98
Inventories:		
Gas stored underground	166	154
Materials and supplies	126	121
Prepaid expenses and other	100	165
Total current assets	6,463	5,969
Property, Plant and Equipment		
Electric	20,468	18,922
Gas	8,355	8,123
Construction work in progress	379	427
Total property, plant and equipment	29,202	27,472
Accumulated depreciation	(11,100)	(13,515)
Net property, plant and equipment	18,102	13,957
Other Noncurrent Assets		
Regulatory assets	2,001	2,011
Nuclear decommissioning funds	1,478	1,335
Other	1,022	1,300
Total other noncurrent assets	4,501	4,646
TOTAL ASSETS	\$ 29,066	\$ 24,572

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, A Debtor-In-Possession
CONSOLIDATED BALANCE SHEETS
(in millions, except per share amounts)

	Balance at December 31,	
	2003	2002
LIABILITIES AND SHAREHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Long-term debt, classified as current	\$ 310	\$ 281
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	657	380
Related parties	224	130
Regulatory balancing accounts	186	364
Other	365	374
Interest payable	153	126
Deferred income taxes	86	—
Other	637	625
Total current liabilities	2,908	2,570
Noncurrent Liabilities		
Long-term debt	2,431	2,739
Rate reduction bonds	870	1,160
Regulatory liabilities	3,979	1,461
Asset retirement obligations	1,218	—
Deferred income taxes	1,334	1,485
Deferred tax credits	127	144
Preferred stock with mandatory redemption provisions	137	—
Other	1,471	1,274
Total noncurrent liabilities	11,567	8,263
Liabilities Subject to Compromise		
Financing debt	5,603	5,605
Trade creditors	3,899	3,803
Total liabilities subject to compromise	9,502	9,408
Commitments and Contingencies (Notes 1, 2 and 12)	—	—
Preferred Stock With Mandatory Redemption Provisions		
6.30% and 6.57%, outstanding 5,500,000 shares, due 2002-2009	—	137
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	1,964	1,964
Reinvested earnings	1,706	805
Accumulated other comprehensive loss	(6)	—
Total shareholders' equity	5,089	4,194
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$29,066	\$24,572

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, A Debtor-In-Possession
CONSOLIDATED STATEMENTS OF CASH FLOWS
(in millions)

	Year Ended December 31,		
	2003	2002	2001
Cash Flows From Operating Activities			
Net income	\$ 923	\$ 1,819	\$ 1,015
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, amortization and decommissioning	1,218	1,193	896
Deferred income taxes and tax credits, net	(75)	378	(306)
Reversal of ISO accrual	—	(970)	—
Other deferred charges and noncurrent liabilities	581	102	(954)
Gain on sale of assets	(29)	—	—
Cumulative effect of a change in accounting principle	1	—	—
Net effect of changes in operating assets and liabilities:			
Restricted cash	(253)	(97)	(3)
Accounts receivable	(590)	212	105
Inventories	(17)	62	(57)
Accounts payable	507	198	1,312
Accrued taxes	48	(345)	1,415
Regulatory balancing accounts, net	(329)	(23)	311
Other working capital	29	11	711
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(87)	(1,442)	(16)
Other, net	43	36	336
Net cash provided by operating activities	1,970	1,134	4,765
Cash Flows From Investing Activities			
Capital expenditures	(1,698)	(1,546)	(1,343)
Net proceeds from sale of asset	49	11	—
Other, net	(114)	26	5
Net cash used by investing activities	(1,763)	(1,509)	(1,338)
Cash Flows From Financing Activities			
Net repayments under credit facilities and short-term borrowings	—	—	(28)
Long-term debt matured, redeemed, or repurchased	(281)	(333)	(111)
Rate reduction bonds matured	(290)	(290)	(290)
Other, net	—	—	(1)
Net cash used by financing activities	(571)	(623)	(430)
Net change in cash and cash equivalents	(364)	(998)	2,997
Cash and cash equivalents at January 1	3,343	4,341	1,344
Cash and cash equivalents at December 31	\$ 2,979	\$ 3,343	\$ 4,341
Supplemental disclosures of cash flow information			
Cash received for:			
Reorganization interest income	\$ 39	\$ 75	\$ 87
Cash paid for:			
Interest (net of amounts capitalized)	773	1,105	361
Income taxes paid (refunded), net	648	1,186	(556)
Reorganization professional fees and expenses	99	99	19
Supplemental disclosures of noncash investing and financing activities			
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	181	419	11,400

See accompanying Notes to the Consolidated Financial Statements.

Pacific Gas and Electric Company, A Debtor-In-Possession
CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY
(in millions)

(in millions, except share amounts)	Common Stock	Additional Paid-in Capital	Common Stock Held by Subsidiary	Reinvested Earnings (Accumu- lated Deficit)	Accumu- lated Other Compre- hensive Income (Loss)	Total Common Share- holders' Equity	Preferred Stock Without Mandatory Redemption Provisions	Comprehensive Income (Loss)
Balance December 31, 2000	\$1,606	\$1,964	\$(475)	\$(1,979)	\$ –	\$1,116	\$294	
Net Income	–	–	–	1,015	–	1,015	–	\$1,015
Cumulative effect of adoption of SFAS No. 133 (net of income tax expense of \$62 million)	–	–	–	–	90	90	–	90
Mark-to-market adjustments for hedging (net of income tax benefit of \$3 million)	–	–	–	–	(5)	(5)	–	(5)
Net reclassification to earnings (net of income tax benefit of \$58 million)	–	–	–	–	(85)	(85)	–	(85)
Foreign currency translation adjustments (net of income tax benefit of \$1 million)	–	–	–	–	(2)	(2)	–	(2)
Comprehensive income								\$1,013
Preferred stock dividend requirement	–	–	–	(25)	–	(25)	–	
Balance December 31, 2001	1,606	1,964	(475)	(989)	(2)	2,104	294	
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 requirement	–	–	–	(25)	–	(25)	–	
Balance December 31, 2002	1,606	1,964	(475)	805	–	3,900	294	
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 requirement	–	–	–	(22)	–	(22)	–	
Balance December 31, 2003	\$1,606	\$1,964	\$(475)	\$ 1,706	\$ (6)	\$4,795	\$294	

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, electricity transmission, and natural gas 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. The Utility served approximately 4.9 million electricity distribution customers and approximately 3.9 million natural gas distribution customers at December 31, 2003. Both PG&E Corporation and the Utility are headquartered in San Francisco, California.

As discussed further in Note 2, on April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the federal Bankruptcy Code, or Bankruptcy Code, in the U.S. Bankruptcy Court for the Northern District of California. The Utility retained control of its assets and is authorized to operate its business as a debtor-in-possession during its Chapter 11 proceeding.

PG&E Corporation's other significant subsidiary is National Energy & Gas Transmission, Inc., formerly known as PG&E National Energy Group, Inc., or PG&E NEG, headquartered in Bethesda, Maryland. PG&E NEG was incorporated on December 18, 1998, as a wholly owned subsidiary of PG&E Corporation. On July 8, 2003, PG&E NEG and certain of its subsidiaries filed voluntary petitions for relief under the provisions of Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Maryland, Greenbelt Division. Subsequently, on July 29, 2003, two additional subsidiaries of PG&E NEG also filed voluntary Chapter 11 petitions. PG&E NEG and those subsidiaries in Chapter 11 retain control of their assets and are authorized to operate their businesses as debtors-in-possession while being subject to the jurisdiction of the bankruptcy court. On October 3, 2003, the bankruptcy court authorized PG&E NEG to change its name to National Energy & Gas Transmission, Inc., or NEGT. The change reflects NEGT's pending separation from PG&E Corporation. Consequently, all subsequent references to PG&E NEG in these Notes to the Consolidated Financial Statements will refer to NEGT. NEGT's proposed plan of reorganization if implemented, would eliminate PG&E Corporation's equity interest in NEGT.

Under accounting principles generally accepted in the United States of America, or GAAP, consolidation is generally required for investments of more than 50% of the outstanding voting stock of an investee, except when control is not held by the majority owner. Under these rules, 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 are not affiliated with PG&E Corporation. As a result, PG&E Corporation no longer retains significant influence over the ongoing operations of NEGT. PG&E Corporation anticipates that the bankruptcy court will approve NEGT's proposed plan of reorganization, or a plan with similar equity elimination provisions for PG&E Corporation. Therefore, effective July 8, 2003, PG&E Corporation no longer consolidates the earnings and losses of NEGT or its subsidiaries and has reflected its ownership interest in NEGT utilizing the cost method of accounting, under which PG&E Corporation's investment in NEGT is reflected as a single amount on the Consolidated Balance Sheet of PG&E Corporation at December 31, 2003. In addition, for the reasons described above, PG&E Corporation considers 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 years, are reflected as discontinued operations in the Consolidated Financial Statements (see Note 5 for further information).

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. All significant intercompany transactions have been eliminated from the Consolidated Financial Statements.

The preparation of financial statements in conformity with 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. As these estimates involve judgments on a wide range of factors, including future economic conditions that are difficult to predict, actual results could differ from these estimates.

Accounting principles used include those necessary for rate-regulated enterprises, which reflect the financial impact of ratemaking policies of the California Public Utilities Commission, or the CPUC, and the Federal Energy Regulatory Commission, or the FERC.

PG&E Corporation's and the Utility's Consolidated Financial Statements have been prepared 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, and on a going-concern basis, which contemplates continuity of operation, realization of assets, and liquidation of liabilities in the ordinary course of business. As a result of the Utility's Chapter 11 filing, the realization of assets and liquidation of liabilities are subject to uncertainty. Under SOP 90-7, certain claims against the Utility existing before the Utility's Chapter 11 filing are 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 are reported separately as reorganization items. Finally, the extent to which the Utility's reported interest expense differs from its stated contractual interest is disclosed on the Utility's Consolidated Statements of Operations.

Reclassifications

Certain amounts in the 2002 and 2001 Consolidated Financial Statements have been reclassified to conform to the 2003 presentation. These reclassifications did not affect the consolidated net income reported by PG&E Corporation and the Utility for the periods presented.

Earnings (Loss) Per Share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per share is computed by dividing net income (loss), adjusted for the net interest and amortization associated with PG&E Corporation's Convertible Subordinated Notes, by the sum of the weighted average number of common shares outstanding and the assumed issuance of common shares for all dilutive securities.

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,		
	2003	2002	2001
(in millions, except per share amounts)			
Income from continuing operations	\$ 791	\$ 1,723	\$1,021
Discontinued operations	(365)	(2,536)	69
Net income (loss) before cumulative effect of changes in accounting principles	426	(813)	1,090
Cumulative effect of changes in accounting principles	(6)	(61)	9
Net Income (Loss)	420	(874)	1,099
Add income impact of assumed conversions:			
Interest expense on 9.5% Convertible Subordinated Notes, net of tax	17	8	—
Net Income (Loss) for Diluted Calculations	\$ 437	\$ (866)	\$1,099
Weighted average common shares outstanding, basic	385	371	363
Add incremental shares from assumed conversions:			
Employee Stock Options, Restricted Stocks and PG&E Corporation shares held by grantor trusts	4	2	1
PG&E Corporation Warrants	5	2	—
9.5% Convertible Subordinated Notes	19	9	—
Shares outstanding for diluted calculations	413	384	364

	Year Ended December 31,		
	2003	2002	2001
(in millions, except per share amounts)			
Earnings (Loss) Per Common Share, Basic			
Income from continuing operations	\$ 2.05	\$ 4.64	\$2.81
Discontinued operations	(0.94)	(6.84)	0.19
Cumulative effect of changes in accounting principles	(0.02)	(0.16)	0.02
Rounding	—	—	0.01
Net earnings (loss)	\$ 1.09	\$(2.36)	\$3.03
Earnings (Loss) Per Common Share, Diluted			
Income from continuing operations	\$ 1.96	\$ 4.50	\$2.80
Discontinued operations	(0.88)	(6.60)	0.19
Cumulative effect of changes in accounting principles	(0.02)	(0.16)	0.02
Rounding	—	—	0.01
Net earnings (loss)	\$ 1.06	\$(2.26)	\$3.02

PG&E Corporation reflects the preferred dividends of its subsidiary as other expense for computation of both basic and diluted earnings per share.

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 CPUC or the FERC.

Adoption of New Accounting Policies

Consolidation of Variable Interest Entities

In December 2003, the Financial Accounting Standards Board, or the FASB, issued Interpretation No. 46 (revised December 2003), “Consolidation of Variable Interest Entities,” or FIN 46R, replacing Interpretation No. 46, “Consolidation of Variable Interest Entities,” or FIN 46, which was issued in January 2003. FIN 46R was issued to replace FIN 46, and to clarify the required accounting for interests in variable interest entities. A variable interest entity is an entity that does not have sufficient equity investment at risk, or the holders of the equity instruments lack the essential characteristics of a controlling financial interest. A variable interest entity is to be consolidated by a company if that company is subject to a majority of the risk of loss from the variable interest entity’s activities, or is entitled to receive a majority of the entity’s residual returns, or both.

PG&E Corporation and the Utility must apply the provisions of FIN 46R as of January 1, 2004. PG&E Corporation and the Utility are continuing to evaluate the impacts of FIN 46R’s initial recognition, measurement and disclosure provisions on their Consolidated Financial Statements and are unable to estimate the impact, if any, which will result when FIN 46R becomes effective. The Utility has investments in unconsolidated affiliates, which are mainly engaged in the purchase of low-income residential real estate property. It is reasonably possible that the Utility will be required to consolidate its interests in these entities as a result of the adoption of FIN 46R. At December 31, 2003, the Utility’s recorded investment in these entities was approximately \$21 million. As a limited partner, the Utility’s exposure to potential loss is limited to its investment in each partnership.

Reporting Realized Gains and Losses on Derivative Instruments Held for Non-Trading Purposes

On October 1, 2003, PG&E Corporation and the Utility adopted the Emerging Issues Task Force, or EITF, Issue No. 03-11, “Reporting Realized Gains and Losses on Derivative Instruments Not Held for Trading Purposes That Are Subject to FASB Statement No. 133, “Accounting for Derivative Instruments and Hedging Activities,” and Not Held for Trading Purposes as Defined in EITF Issue No. 02-3, “Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities.” Under EITF Issue No. 03-11, the determination of whether realized gains and losses on derivative instruments held

for non-trading purposes should be reported on a net or gross basis is a matter of judgment that depends on the relevant facts and circumstances and the economic substance of the transaction.

For all non-trading derivative instruments that do not qualify for cash flow hedge accounting treatment, PG&E Corporation and the Utility report both realized and unrealized gains and losses on a net basis in the Consolidated Statement of Operations. The financial reporting requirements reflected in EITF Issue No. 03-11 did not have any impact on the Consolidated Financial Statements of PG&E Corporation and the Utility, nor did they result in any reclassifications of revenues and expenses.

Amendment of Statement 133 on Derivative Instruments and Hedging Activities

On July 1, 2003, PG&E Corporation and the Utility adopted SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities," or SFAS No. 149. SFAS No. 149 amends and clarifies the accounting and reporting for derivative instruments, including the criteria for qualifying for the normal purchases and sales exception, certain derivative instruments embedded in other contracts and for hedging activities. SFAS No. 149 also clarifies circumstances under which a contract with an initial net investment meets the characteristics of a derivative instrument according to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, or SFAS No. 133. The provisions of SFAS No. 149 that relate to SFAS No. 133 Implementation Issues that have been effective for periods that began prior to June 15, 2003 continue to be applied in accordance with their respective effective dates.

The requirements of SFAS No. 149 are effective for derivative instruments entered into or modified after June 30, 2003 and for hedging relationships designated after June 30, 2003. The adoption of SFAS No. 149 did not have a material impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

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.

Determining Whether an Arrangement Contains a Lease

In May 2003, the EITF reached consensus on EITF Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease," or EITF 01-8. EITF 01-8 establishes criteria to be applied to any new or modified agreement in order to ascertain if the agreement is in effect a lease and subject to lease accounting treatment and disclosure requirements principally found in SFAS No. 13, "Accounting for Leases". EITF 01-8 is effective for all new or modified arrangements entered into as of July 1, 2003. The adoption of EITF 01-8 did not have a material impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

Guarantor's Accounting and Disclosure Requirements for Guarantees

PG&E Corporation incorporated the disclosure requirements of FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others," or FIN 45, into its December 31, 2002 disclosure of guarantees. Beginning January 1, 2003, PG&E Corporation applied the initial recognition and measurement provisions of FIN 45 to guarantees issued or modified after December 31, 2002.

FIN 45 elaborates on existing disclosure requirements for most guarantees. It also clarifies that at the time a company issues a guarantee, it must recognize a liability for the fair value of the obligation it assumes under that guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that

specified triggering events or conditions occur. This information also must be disclosed in interim and annual financial statements.

The adoption of this interpretation did not have a material impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

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. SFAS No. 143 provides accounting requirements for costs associated with legal obligations to retire tangible long-lived assets. 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 impacts of adopting SFAS No. 143 were as follows:

- The Utility identified its nuclear generation and certain fossil generation facilities as having asset retirement obligations as of January 1, 2003. No additional asset retirement obligations had been identified as of December 31, 2003. Through December 31, 2002, the Utility had recorded approximately \$1.4 billion for its nuclear and fossil decommissioning obligations in accumulated depreciation in the Consolidated Balance Sheets;
- Upon adoption of SFAS No. 143, the Utility reclassified the decommissioning liabilities recorded through December 31, 2002 as asset retirement obligations in the Consolidated Balance Sheets. To record the decommissioning liabilities at fair value as required by SFAS No. 143, the Utility then reduced the asset retirement obligations by approximately \$53 million. The Utility increased its property, plant and equipment balance by approximately \$332 million to reflect the fair value of the asset retirement costs as of the date the obligation was incurred, less accumulated depreciation from the date the obligation was incurred through December 31, 2002. Finally, the Utility recorded a regulatory liability of approximately \$387 million to reflect the cumulative effect of adoption for its nuclear facilities. This regulatory liability represents timing differences between recognition of nuclear decommissioning obligations in accordance with GAAP and the expense recognized for ratemaking purposes. The cumulative effect of the change in accounting principle for the Utility's fossil facilities as a result of adopting SFAS No. 143 was a loss of approximately \$1 million, after-tax;
- In connection with an application filed with the CPUC requesting an increase in the Utility's nuclear decommissioning revenue requirements for the years 2003 through 2005, during 2003 the Utility developed a new estimate for costs to decommission its nuclear facilities. As a result, the Utility reduced its asset retirement obligation by approximately \$223 million from the amount recorded upon the Utility's adoption of SFAS No. 143 on January 1, 2003. The Utility also reduced its property, plant and equipment balance by approximately \$61 million. Finally, to account for timing differences between recognition of the modified asset retirement obligation as recorded in accordance with GAAP and ratemaking purposes, the Utility increased its regulatory liability by approximately \$162 million;

If SFAS No. 143 had been adopted on January 1, 2002, the pro forma effects on earnings of the accounting change for the year ended December 31, 2002 would not have been material. The amounts recorded upon adoption of SFAS No. 143 reflect the pro forma effects on the Consolidated Balance Sheets had SFAS No. 143 been adopted on December 31, 2002;

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 \$1.4 billion at December 31, 2003 and approximately \$1.3 billion at December 31, 2002;

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; and

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 recent guidance from the staff of the Securities and Exchange Commission, or SEC, the Utility reclassified this obligation to a regulatory liability in its December 31, 2003 balance sheet. The Utility's estimated removal costs recorded as a regulatory liability were approximately \$1.8 billion at December 31, 2003 and approximately \$1.6 billion at December 31, 2002, recorded in accumulated depreciation.

Accounting for Costs Associated with Exit or Disposal Activities

On January 1, 2003, PG&E Corporation adopted SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," or SFAS No. 146. SFAS No. 146 supersedes previous accounting guidance, principally EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity," or EITF 94-3. SFAS No. 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF 94-3, a liability for an exit cost is recognized at the commitment date of an exit plan. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. The adoption of SFAS No. 146 did not have any impact on the Consolidated Financial Statements of PG&E Corporation or the Utility at the date of adoption.

Accounting for Goodwill and Other Intangible Assets

PG&E Corporation and the Utility had no goodwill on their Consolidated Balance Sheets at December 31, 2003 or 2002. Other intangible assets consist mainly of hydroelectric facility licenses and other agreements. The gross carrying amount of the hydroelectric facility licenses and other agreements was approximately \$73 million at December 31, 2003 and \$67 million at December 31, 2002. The accumulated amortization was approximately \$19 million at December 31, 2003 and \$16 million at December 31, 2002.

The Utility's amortization expense related to intangible assets was approximately \$3 million in 2003, \$3 million in 2002 and \$2 million in 2001. The estimated annual amortization expense for the Utility's intangible assets for 2004 through 2008 is approximately \$3 million.

Significant Accounting Policies

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 Fiduciary Trust Company International that were greater than 10% of PG&E Corporation's and the Utility's total cash and cash equivalents balance at December 31, 2003.

Restricted Cash

Restricted cash includes deposits under certain third party agreements, amounts held in escrow as collateral required by the California Independent System Operator, or ISO, and other counterparties and deposits securing workers' compensation obligations. In addition, certain amounts designated as restricted by management related to the tax dispute with NEGT and discussed in Note 12 are included within other noncurrent assets on PG&E Corporation's Consolidated Balance Sheet at December 31, 2003.

Inventories

Inventories include materials, supplies and gas stored underground that are valued at average cost.

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.

NEGT is included in the consolidated tax return of PG&E Corporation. As discussed in Note 12, NEGТ and its creditors have filed a complaint against PG&E Corporation and two PG&E Corporation officers who previously served on NEGТ's Board of Directors, asserting, among other claims, that NEGТ is entitled to be compensated under an alleged tax sharing agreement between PG&E Corporation and NEGТ for any tax savings achieved as a result of incorporation of losses, deductions and tax credits related to NEGТ or its subsidiaries in PG&E Corporation's consolidated federal tax returns. PG&E Corporation disputes this assertion.

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, 2003, the Utility's recorded investment in these entities totaled approximately \$21 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 NEGТ Energy Trading Holdings Corporation, or NEGТ ET, formerly known as PG&E Energy Trading Holdings Corporation. Both GTNW and NEGТ ET are subsidiaries of NEGТ. The Utility sold natural gas transportation capacity and other ancillary services to NEGТ ET until NEGТ'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 are eliminated in consolidation; therefore, no profit or loss resulted from these transactions. Beginning July 8, 2003, the Utility's transactions with NEGТ 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,	
	2003	2002	2001	2003	2002
(in millions)					
Utility revenues from:					
Administrative services provided to PG&E Corporation	\$ 8	\$ 7	\$ 6	\$ —	\$ 1
Natural gas transportation capacity services provided to NEGТ ET	8	9	11	—	—
Contribution in aid of construction received from NEGТ	—	2	5	—	3
Trade deposit due from GTNW	3	—	11	15	12
Other	—	—	1	—	—

	Year Ended December 31,			Receivable (Payable) Balance Outstanding at Year Ended December 31,	
	2003	2002	2001	2003	2002
(in millions)					
Utility expenses from:					
Administrative services received from PG&E Corporation	\$183	\$106	\$127	\$(396)	\$(289)
Interest accrued on pre-petition liabilities due to PG&E Corporation	6	8	3	(2)	(2)
Administrative services received from NEGT	2	2	–	(1)	(2)
Software purchases from NEGT ET	1	–	–	–	–
Natural gas commodity services received from NEGT ET	10	49	120	–	(26)
Natural gas transportation services received from GTNW	58	47	40	(8)	(8)
Trade deposit due to NEGT ET	(7)	7	–	–	(7)

Property, Plant and Equipment

Property, plant and equipment are reported at their original cost, unless impaired under the provisions of SFAS No. 144. Original costs include:

- Labor and materials;
- Construction overhead; and
- Capitalized interest or an allowance for funds used during construction, or AFUDC.

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. PG&E Corporation and the Utility had capitalized interest and AFUDC of approximately \$29 million at December 31, 2003, \$27 million at December 31, 2002 and \$18 million at December 31, 2001.

Depreciation – The Utility’s composite depreciation rate was 3.42% in 2003, 3.42% in 2002 and 3.63% in 2001.

	Gross Plant (in millions)	Estimated useful lives
Electricity generating facilities	\$ 1,543	15 to 50 years
Electricity distribution facilities	13,315	16 to 63 years
Electricity transmission	3,418	27 to 65 years
Natural gas distribution facilities	4,499	28 to 49 years
Natural gas transportation	2,365	25 to 45 years
Natural gas storage	280	25 to 48 years
Other	3,403	5 to 40 years
Total	\$28,823	

The useful lives of the Utility’s property, plant and equipment are authorized by the CPUC. Depreciation rates include a component for the cost of asset retirement net of salvage value. 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 charged 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, “Accounting for the Effects of Certain Types of Regulation,” as amended, or SFAS No. 71, which include electricity and natural gas distribution, electricity transmission, and natural gas transportation and storage.

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 capitalizes costs incurred during the application development stage of internal use software projects to property, plant and equipment. Capitalized software costs totaled \$273 million at December 31, 2003 and \$303 million at December 31, 2002, net of accumulated amortization of approximately \$159 million at December 31, 2003 and \$121 million at December 31, 2002. PG&E Corporation amortizes capitalized software costs ratably over the expected lives of the projects ranging from 3 to 15 years, commencing operational use, in accordance with regulatory requirements and recovery.

Impairment of Long-Lived Assets

The carrying values of long-lived assets are evaluated in accordance with the provisions of SFAS No. 144. SFAS No. 144 became effective at the beginning of 2003 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 2002 and 2003, NEGT recorded certain impairment charges in accordance with SFAS No. 144 (see Note 5).

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 ratemaking principles. 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, short-term borrowings, accounts payable, customer deposits and the Utility’s variable rate pollution control loan agreements approximate their carrying values as of December 31, 2003 and 2002;
- The fair values of rate reduction bonds, PG&E Corporation’s 6 7/8% Senior Secured Notes, the Utility’s preferred stock and the Utility’s 7.90% deferrable interest subordinated debentures were determined based on quoted market prices; and
- The fair value of debt for which no market quotation is readily available, was determined with the assistance of third-party experts and using estimates of borrowing rates currently available to PG&E Corporation and the Utility for instruments of similar maturity. The fair value of a small portion of the Utility’s debt was determined using the present value of future cash flows. The fair value of PG&E Corporation’s 9.5% convertible subordinated debt was determined using the present value of future cash flows and the Black-Scholes option valuation model, including a stock volatility assumption of 35%.

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 on the Consolidated Balance Sheets):

	At December 31,			
	2003		2002	
	Carrying amount	Fair value	Carrying amount	Fair value
(in millions)				
Long-term debt (Note 3):				
PG&E Corporation				
6 7/8% Senior Secured Notes	\$ 600	\$ 646	\$ —	\$ —
Convertible subordinated notes	280	649	280	280
Utility	4,839	4,905	5,120	4,906
Rate reduction bonds (Note 4)	1,160	1,252	1,450	1,580
Utility preferred stock with mandatory redemption provisions (Note 7)	137	167	137	132

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 SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. SFAS No. 71 applies to all of the Utility's operations except for its generation operations and a natural gas pipeline expansion project. The Utility is regulated by the CPUC, the FERC and the Nuclear Regulatory Commission, or NRC, among others.

SFAS No. 71 provides for the recording of 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 would be written off.

Regulatory Assets

Regulatory assets comprise the following:

	Balance at December 31,	
	2003	2002
(in millions)		
Rate reduction bond assets	\$1,054	\$1,346
Regulatory assets for deferred income tax	324	229
Unamortized loss, net of gain, on reacquired debt	277	299
Post-transition period contract termination costs	151	—
Environmental compliance costs	139	102
Other, net	56	35
Total regulatory assets	\$2,001	\$2,011

Regulatory assets are charged to expense during the period that the costs are reflected in regulated revenues.

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 23 years. The Utility's regulatory asset relating to post-transition period contract termination costs is being amortized and collected in rates on a straight-line basis until the end of September 2014, the contract's original termination date. 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.

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 asset relating to unamortized loss, net of gain on reacquired debt.

Regulatory Liabilities

Regulatory liabilities comprise the following:

	Balance at December 31,	
	2003	2002
(in millions)		
Cost of removal obligation	\$1,810	\$ –
Employee benefit plans	925	1,102
Asset retirement costs	584	–
Public purpose programs	185	182
Rate reduction bonds	175	102
Surcharge liability	125	–
Other	175	75
Total regulatory liabilities	\$3,979	\$1,461

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. Historically, these removal costs have been recorded in accumulated depreciation; however, as a result of recent guidance from the staff of the SEC, the Utility reclassified this obligation to a regulatory liability during 2003. 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, based on the adoption of SFAS No. 143 on January 1, 2003, and the amounts recognized for ratemaking purposes. 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 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 ratepayers in the future.

The Utility's regulatory liability related to surcharge revenues represents the estimated amount of previously collected surcharge revenues expected to be refunded to customers based upon current proceedings at the CPUC. In early January 2004, the CPUC issued a decision finding that the rate freeze mandated by AB 1890 ended on January 18, 2001. In mid-January 2004, the Utility entered into a rate design settlement agreement, or rate design settlement, with representatives of major customer groups that addresses revenue allocation and rate design issues associated with the decrease in the Utility's revenue requirement resulting from the Settlement Agreement, DWR revenue requirements, and other CPUC actions. On February 11, 2004, a proposed decision was issued that would adopt the rate design settlement with a modification for DWR revenues. This proposed decision, if approved by the CPUC, combined with the January 2004 CPUC decision regarding the rate freeze, provides that the Utility will no longer collect the frozen rates and surcharges. Instead, it will collect the regulatory assets arising from the Settlement Agreement, as amortized into rates, and the revenue requirements established by the 2003 general rate case, or GRC, settlement discussed below as well as revenue requirements established in other proceedings. The CPUC's proposed decision adopts the Utility's request to revise electricity rates reflecting the terms of the rate design settlement based

on the Utility's overall forecast revenue requirements for 2004. If ultimately approved, the Utility's electricity customers would receive an electricity rate reduction of approximately 8.0%, on average, in March 2004, or shortly thereafter retroactive to January 1, 2004. The Utility expects that as a result of this rate reduction, electricity operating revenues would decrease by approximately \$799 million compared to revenues generated at current rates. As a result of the anticipated rate decrease incorporating a refund of some surcharge revenues collected in 2003, the Utility has established a \$125 million regulatory liability at December 31, 2003. In addition, if the 2003 GRC settlement is not approved, the net average reduction in electricity rates and associated reduction in electricity operating revenue will be even greater.

Regulatory Balancing Accounts

Sales balancing accounts accumulate differences between recorded revenues and revenues the Utility is authorized to collect through rates. Cost balancing accounts accumulate differences between recorded costs and costs the Utility is authorized to recover through rates. Under-collections that are probable of recovery are recorded as regulatory balancing account assets. Over-collections 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.

As a result of the California energy crisis discussed in Note 2, the Utility could no longer conclude that power generation and procurement-related balancing accounts met the requirements of SFAS No. 71. However, the Utility continues to record balancing accounts associated with its electricity transmission and distribution and natural gas transportation businesses.

In 2002 and 2003, the CPUC ordered the Utility to create certain electricity balancing accounts to track specific electric-related amounts, including shortfalls from baseline allowance increases and costs related to the self-generation incentive program, for which the CPUC has not yet determined the recovery method for these costs. In the decisions ordering the creation of these balancing accounts, the CPUC indicated that the recovery method of these amounts would be determined in the future. Because the Utility cannot conclude that the amounts in these balancing accounts are considered probable of recovery in future rates, the Utility has reserved these balances by recording a charge against earnings. As of December 31, 2003, the reserve for these balances was approximately \$200 million.

The Utility's current regulatory balancing account assets comprise the following:

	Balance at December 31,	
	2003	2002
(in millions)		
Natural gas revenue balancing accounts	\$ 23	\$38
Natural gas cost balancing accounts	55	60
Electricity revenue balancing accounts	75	—
Electricity distribution cost balancing accounts	95	—
Total	\$248	\$98

The Utility's current regulatory balancing account liabilities comprise the following:

	Balance at December 31,	
	2003	2002
(in millions)		
Natural gas revenue balancing accounts	\$ 13	\$ 4
Natural gas cost balancing accounts	158	226
Electricity transmission and distribution revenue balancing accounts	6	98
Electricity transmission cost balancing accounts	9	36
Total	\$186	\$364

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, were 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.

Accounting for Price Risk Management Activities

PG&E Corporation, through the Utility, engages in price risk management activities for non-trading purposes. Non-trading derivative instruments designated as cash flow hedges are entered into to hedge variable price risk associated with the purchase and sale of commodities and to hedge variable interest rates on long-term debt. 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 portfolio and interest rate hedges related to the issuance of debt under the Utility's Plan of Reorganization.

Derivative instruments associated with non-trading activities include forward contracts, futures, swaps, options and other contracts. They are accounted for at fair value unless they qualify for the normal purchases and sales exemption as further discussed below.

Derivative instruments that are recorded on PG&E Corporation's and the Utility's Consolidated Balance Sheets are presented in other current assets. 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 is 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 are deferred and recorded in regulatory liabilities and regulatory assets to the extent they are recoverable in future rates.

PG&E Corporation and the Utility discontinue hedge accounting prospectively if they determine 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 because the derivative instrument no longer qualifies as an effective hedge, then 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 for which hedge accounting has been discontinued that were previously recorded in accumulated other comprehensive income will remain in accumulated other comprehensive income until the hedged item is recognized in earnings, unless the forecasted transaction is no longer probable of occurring. If hedge accounting is discontinued because the forecasted transaction is no longer probable of occurring, then the gains and losses from the derivative instrument that were previously recorded in accumulated other comprehensive income will be immediately recognized in earnings. When the hedged item matures or is sold, the gains and losses deferred in accumulated other comprehensive income are recognized in earnings.

Net realized and unrealized gains or losses on non-trading 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.

Non-trading derivative instruments that are not designated as hedges or that are not eligible for the normal purchases and sales exception are adjusted to fair value through income.

The Utility estimates the fair value of its contracts 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, the Utility uses models to estimate fair value.

PG&E Corporation and the Utility have derivative commodity instruments for the physical delivery of purchase and sale quantities transacted in the normal course of business. These derivative instruments are exempt from the requirements of SFAS No. 133 under the normal purchase and sales exception, and are not reflected on the balance sheet at fair value. Derivative instruments treated as normal purchases or sales are recorded and recognized in income using accrual accounting. Therefore, revenues are recognized as earned and expenses are recognized as incurred.

The Utility has commodity contracts that are not derivative instruments. Revenues are recorded as earned and expenses are recognized as incurred.

Stock-Based Compensation

PG&E Corporation and the Utility account for stock-based compensation using the intrinsic value method in accordance with the provisions of Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees," 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 Disclosures, 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. If compensation expense had been recognized using the fair value-based method under SFAS No. 123 and using valuation assumptions disclosed in Note 10, then PG&E Corporation's pro forma consolidated earnings (loss) and earnings (loss) per share would have been as follows:

	Year Ended December 31,		
	2003	2002	2001
(in millions, except per share amounts)			
Net earnings (loss):			
As reported	\$ 420	\$ (874)	\$1,099
Deduct: Total stock-based employee compensation expense determined under the fair value-based method for all awards, net of related tax effects	(19)	(20)	(23)
Pro forma	\$ 401	\$ (894)	\$1,076
Basic earnings (loss) per share:			
As reported	1.09	(2.36)	3.03
Pro forma	1.04	(2.41)	2.96
Diluted earnings (loss) per share:			
As reported	1.06	(2.26)	3.02
Pro forma	1.01	(2.32)	2.96

Had compensation expense 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,		
	2003	2002	2001
(in millions)			
Net Earnings:			
As reported	\$901	\$1,794	\$1,015
Deduct: Total stock-based employee compensation expense determined under fair value-based method for all awards, net of related tax effects	(8)	(7)	(7)
Pro forma	\$893	\$1,787	\$1,008

Accumulated Other Comprehensive (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 Transaction in Accordance with SFAS No. 133	Foreign Currency Translation Adjustment	Retirement Plan Remeasurement	Other	Accumulated Other Comprehensive Income (Loss)
Balance December 31, 2000	\$ –	\$(4)	\$ –	\$ –	\$ (4)
Period change in:					
Cumulative effect of adoption of SFAS No. 133 and interpretations	(243)	–	–	–	(243)
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	237	–	–	–	237
Net reclassification to earnings	42	–	–	–	42
Other	–	(1)	–	(1)	(2)
Balance 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 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 December 31, 2003	\$ (81)	\$ –	\$(4)	\$ –	\$ (85)

Amounts included in accumulated other comprehensive income (loss) related to discontinued operations were \$(77) million at December 31, 2003, and \$(93) million at December 31, 2002.

NOTE 2: THE UTILITY CHAPTER 11 FILING

On April 6, 2001, the Utility filed a voluntary petition for relief under the provisions of Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the Northern District of California. The Utility has retained control of its assets and is authorized to operate its business as a debtor-in-possession during its Chapter 11

proceeding. PG&E Corporation and 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), are not included in the Utility's Chapter 11 proceeding.

Claims filed in the Chapter 11 proceeding totaled approximately \$51.5 billion. Of these claims, approximately \$9.8 billion related to ISO, Power Exchange, or PX, and generator claims. Under a bankruptcy court order the aggregate allowable amount of ISO, PX and generator claims is limited to approximately \$1.6 billion after giving effect to approximately \$200 million in pre-petition offset. The Utility expects that this approximately \$1.6 billion amount will be further reduced as a result of certain proceedings pending at the FERC. Of the approximately \$43.3 billion of filed claims that remained, approximately \$23.8 billion has been disallowed by the bankruptcy court due to objections, claim withdrawals and agreements with claimants. The Utility has objected to, or intends to object to, approximately \$900 million of the remaining approximately \$19.5 billion of filed claims. In addition, of the remaining approximately \$19.5 billion of filed claims, approximately \$5.5 billion are expected to pass through the Chapter 11 proceeding and be satisfied in the ordinary course of business. Since the Utility's filing under Chapter 11 in April 2001, the Utility has made approximately \$2.0 billion in claims-related principal payments.

The Utility has recorded its estimate of all valid claims at December 31, 2003 as approximately \$9.5 billion of liabilities subject to compromise, including interest on disputed claims and approximately \$2.7 billion of long-term debt. At December 31, 2002, the Utility had recorded approximately \$9.4 billion of liabilities subject to compromise. The increase from \$9.4 billion is mainly due to interest accruals during the twelve months ended December 31, 2003.

The bankruptcy court has authorized certain payments and actions necessary for the Utility to continue its normal business operations while operating as a debtor-in-possession. For example, the Utility is authorized to pay employee wages and benefits, amounts due under contracts with the majority of qualifying facilities, environmental remediation expenses and expenditures related to property, plant and equipment. In addition, the Utility is authorized to refund certain customer deposits, use certain bank accounts and make cash collateral deposits and assume responsibility for various hydroelectric contracts. The Utility also has received permission from the bankruptcy court to make payments on pre- and post-petition interest on certain claims, pre-petition secured debt that has matured and certain other claims.

The Utility has agreed to pay pre- and post-petition interest on liabilities subject to compromise at the rates set forth below.

(in millions)	Amount Owed	Agreed Upon Interest Rate
		at December 31, 2003 (per annum)
Commercial paper claims	\$ 873	8.216%
Floating rate notes	1,240	8.333%
Senior notes	680	10.375%
Medium-term notes	287	6.560% to 9.200%
Revolving line of credit claims	938	8.750%
Pollution control bonds	814	1.300% to 5.350%
Qualifying facilities	45	5.000%
Other claims	4,625	3.160% to 12.000%
Liabilities subject to compromise at December 31, 2003	\$9,502	

Since the Utility did not emerge from Chapter 11 on or before September 15, 2003, the interest rates for commercial paper claims, floating rate notes, senior notes, medium-term notes and revolving line of credit claims increased 0.75% over the originally agreed upon rates for periods on and after September 15, 2003. The interest rates for these claims will increase by an additional 0.375% if the effective date of a plan of reorganization does not occur on or before March 15, 2004. For other claims, the Utility has recorded interest at the contractual or FERC-tariffed interest rate. When those rates do not apply, the Utility has recorded interest at the federal judgment rate.

Plan of Reorganization

In September 2001, PG&E Corporation and the Utility proposed a plan of reorganization that would have disaggregated the Utility's businesses. In April 2002, the CPUC, later joined by the Official Committee of Unsecured Creditors, proposed an alternate plan of reorganization that would not have disaggregated the Utility's businesses. On December 19, 2003, the CPUC, PG&E Corporation and the Utility entered into a settlement agreement, or the Settlement Agreement, that contemplated a new plan of reorganization to supersede the competing plans. Under the Settlement Agreement, the Utility remains vertically integrated. On December 22, 2003, the bankruptcy court confirmed the new plan of reorganization, or the Plan of Reorganization, which fully incorporates the Settlement Agreement. The Utility expects to pay all allowed creditor claims (except for the claims of holders of pollution control-related bond obligations that will be reinstated) from the proceeds of a public offering of long-term debt, cash on hand, and draws on credit facilities. The Utility also will establish one or more escrow accounts for disputed claims and deposit cash in these accounts. Under the Plan of Reorganization, allowed environmental, fire suppression, pending litigation and tort claims, and workers' compensation claims will be satisfied by the Utility in the ordinary course of business.

On January 20, 2004, several parties filed applications with the CPUC requesting that the CPUC rehear and reconsider its decision approving the Settlement Agreement on the basis that the Settlement Agreement does not comply with California law. Although the CPUC is not required to act on these applications within a specific time period, if the CPUC has not acted on an application within 60 days, that application may be deemed denied for purposes of seeking judicial review. In addition, the two CPUC commissioners who did not vote to approve the Settlement Agreement and a municipality have filed appeals of the bankruptcy court's confirmation order in the U.S. District Court for the Northern District of California, or the District Court, citing similar objections to those included in the request for rehearing and reconsideration of the CPUC's decision. On January 5, 2004, the bankruptcy court denied a request to stay the implementation of the Plan of Reorganization until the appeals are resolved. The District Court will set a schedule for briefing and argument of the appeals at a later date. No additional parties may request rehearings or make appeals of the CPUC's approval of the Settlement Agreement or the bankruptcy court's confirmation order. PG&E Corporation and the Utility cannot predict the timing and outcome of the requests for rehearing and appeals.

The Plan of Reorganization provides that it will not become effective unless and until each of the following conditions is satisfied or waived:

- The effective date occurs on or before March 31, 2004;
- All actions, documents and agreements necessary to implement the Plan of Reorganization are effected or executed;
- The Utility and PG&E Corporation have received all authorizations, consents, regulatory approvals, rulings, letters, no-action letters, opinions or documents that the Utility and PG&E Corporation determine are necessary to implement the Plan of Reorganization;
- The Plan of Reorganization has not been modified in a material way since the date of confirmation;
- The Utility has consummated the sale of the debt securities provided for under the Plan of Reorganization;
- Moody's Investors Service, or Moody's, has issued an issuer rating for the Utility of not less than Baa3 and Standard & Poor's, or S&P, has issued long-term issuer credit ratings for the Utility of not less than BBB-;
- Moody's has issued a credit rating of not less than Baa3 for the debt securities provided for under the Plan of Reorganization and S&P has issued a credit rating of not less than BBB- for the debt securities provided for under the Plan of Reorganization;
- The CPUC has given final approval of the Settlement Agreement;
- The Utility, PG&E Corporation and the CPUC have executed and delivered the Settlement Agreement;
- The CPUC has given final approval for all of the financings, securities and accounts receivable programs provided for in the Plan of Reorganization; and

- The CPUC has given final approval for all rates, tariffs and agreements necessary to implement the Plan of Reorganization.

As described above, the Plan of Reorganization provides that it will not become effective unless and until the CPUC has given final approval of the Settlement Agreement, the financings, securities and accounts receivable programs provided for in the Plan of Reorganization and all rates, tariffs and agreements necessary to implement the Plan of Reorganization. For purposes of these conditions, final approval means approval on behalf of the CPUC that is not subject to any pending appeal or further right of appeal, or approval on behalf of the CPUC that, although subject to a pending appeal or further right of appeal, has been agreed by the Utility and PG&E Corporation to constitute final approval. Thus, the terms of the Plan of Reorganization permit the Utility and PG&E Corporation to cause the Plan of Reorganization to become effective (and permit the Utility to issue the debt securities provided for under the Plan of Reorganization) while the CPUC's approvals are subject to pending appeals or further rights of appeal. In addition, the Plan of Reorganization provides that the Utility may waive the conditions described under the first five bullets listed above.

Principal Terms of the Settlement Agreement

The Settlement Agreement contains a statement of intent that it is in the public interest to restore the Utility to financial health and maintain and improve the Utility's financial condition in the future to ensure that the Utility is able to provide safe and reliable electricity and natural gas to its customers at just and reasonable rates. In addition, the Settlement Agreement includes a statement of intent that it is fair and in the public interest to allow the Utility to recover prior uncollected costs over a reasonable time and to provide for the Utility's shareholders to earn a reasonable rate of return on the Utility's business.

The principal terms of the Settlement Agreement are:

Regulatory Asset

- The Settlement Agreement establishes a \$2.21 billion, after-tax, regulatory asset (which is equivalent to an approximately \$3.7 billion, pre-tax, regulatory asset), or the Regulatory Asset, as a new, separate and additional part of the Utility's rate base that will be amortized on a "mortgage-style" basis over nine years beginning January 1, 2004. Under this amortization methodology, annual after-tax collections of a \$2.21 billion regulatory asset are estimated to range from approximately \$140 million in 2004 to approximately \$380 million in 2012, although these amounts will be reduced as discussed below. The Regulatory Asset will be recognized when it meets the SFAS No. 71 accounting criteria for probability of recovery in rates. Upon recognition of the Regulatory Asset the Utility will reflect a one-time non-cash gain equal to the Regulatory Asset. The Regulatory Asset will be fully amortized by the end of 2012.
- The unamortized balance of the Regulatory Asset will earn a rate of return on its equity component of no less than 11.22% annually for its nine-year term and, after the equity component of the Utility's capital structure reaches 52%, the authorized equity component of this regulatory asset will be no less than 52% for the remaining term. The rate of return on the Regulatory Asset will be reduced if the Utility completes the refinancing discussed below. The equity and debt components of the Utility's rate of return will be eliminated. Instead the Utility would collect from customers amounts sufficient to service the securitized debt.
- The net after-tax amount of any refunds, claim offsets or other credits the Utility receives from energy suppliers relating to specified procurement costs incurred during the California energy crisis and arising from the settlement of CPUC litigation against El Paso Natural Gas Company, or El Paso, related to any electricity (but not natural gas) refunds will reduce the outstanding balance of the Regulatory Asset. On January 26, 2004 in a filing with the CPUC, the Utility proposed to reduce the Regulatory Asset by approximately \$189 million, after-tax, for these matters.

Ratemaking Matters

- The CPUC deemed the Utility's adopted 2003 electricity generation rate base of approximately \$1.6 billion just and reasonable and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. This reaffirmation would allow for the recognition of an additional after-tax regulatory asset of approximately

\$800 million (which is equivalent to an approximately \$1.3 billion pre-tax regulatory asset). This regulatory asset and an equivalent one-time non-cash gain will be recorded when it meets the probability requirements of SFAS No. 71. The individual components of the regulatory assets will be amortized over their respective lives, with a weighted average life of approximately 16 years.

- The CPUC will timely act upon the Utility's applications to collect in rates prudently incurred costs of (including return of and return on) any new and reasonable investment in utility plant and assets and will timely adjust the Utility's rates to ensure that the Utility collects in its rates fixed amounts to service existing rate reduction bonds, Regulatory Asset amortization and return, and base revenue requirements. The Settlement Agreement provides that the CPUC will not discriminate against the Utility because of the Utility's Chapter 11 proceeding and the Utility's previous actions concerning the energy crisis.
- The CPUC will 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%. However, 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%.
- The Utility's retail electricity rates were maintained at current levels through December 31, 2003. The Settlement Agreement includes a statement of intent that as a result of the Settlement Agreement and the Plan of Reorganization, retail electricity rates may be reduced in January 2004 with future reductions expected thereafter.
- The CPUC also agreed to act promptly on certain of the Utility's pending ratemaking proceedings, including the Utility's pending 2003 general rate case, or GRC. The outcome of these proceedings may result in the establishment of additional regulatory assets on the Utility's Consolidated Balance Sheets.

Refinancing Supported by a Dedicated Rate Component

Under the Settlement Agreement, PG&E Corporation and the Utility agreed to seek to refinance the remaining unamortized pre-tax balance of the Regulatory Asset and related federal, state and franchise taxes, up to a total of \$3.0 billion, as expeditiously as practicable after the effective date of the Plan of Reorganization using a securitized financing supported by a dedicated rate component, provided the following conditions are met:

- Authorizing California legislation satisfactory to the CPUC, The Utility Reform Network, or TURN, and the Utility is passed and signed into law allowing securitization of the Regulatory Asset and associated federal and state income and franchise taxes and providing for the collection in the Utility's rates of any portion of the associated tax amounts not securitized;
- The CPUC determines that, on a net present value basis, the refinancing would save customers money over the term of the securitized debt compared to the Regulatory Asset;
- The refinancing will not adversely affect the Utility's issuer or debt credit ratings; and
- The Utility obtains, or decides it does not need, a private letter ruling from the Internal Revenue Service, or IRS, confirming that neither the refinancing nor the issuance of the securitized debt is a presently taxable event.

The Utility would be permitted to complete the refinancing in up to two tranches up to one year apart, and would issue sufficient callable debt or debt with earlier maturities as part of the Plan of Reorganization to accommodate the refinancing supported by a dedicated rate component. Upon refinancing with securitization, the equity and debt components of the Utility's rate of return on the Regulatory Asset would be eliminated. Instead the Utility would collect from customers amounts sufficient to service the securitized debt. The Utility would use the securitization proceeds to rebalance its capital structure in order to maintain the capital structure provided for under the Settlement Agreement.

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 credit rating by Moody's will be no less than A2 and the Utility's long-term issuer credit rating from 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.

Under the Settlement Agreement, the CPUC retains and, after any assumption of the DWR contracts, will retain the right to review the prudence of the Utility's administration and dispatch of the DWR contracts consistent with applicable law.

Headroom

The CPUC agreed and acknowledged that the headroom, surcharge and base revenues accrued or collected by the Utility through and including December 31, 2003 are the property of the Utility's Chapter 11 estate, have been or will be used for utility purposes, including to pay creditors in the Utility's Chapter 11 proceeding, and have been included in the Utility's retail electricity rates consistent with state and federal law. The Settlement Agreement defines headroom as the Utility's total net after-tax income reported under GAAP, less earnings from operations (a non-GAAP financial measure that has been historically reported by PG&E Corporation in its earnings press release), plus after-tax amounts accrued for Chapter 11-related administration and Chapter 11-related interest costs, all multiplied by 1.67, provided that the calculation reflects the outcome of the Utility's 2003 GRC. The Settlement Agreement provides that if headroom revenue accrued by the Utility during 2003 is greater than \$875 million, pre-tax, the Utility will refund the excess to ratepayers.

Dismissal of Filed Rate Case, Other Litigation, and Regulatory Proceedings

- On or as soon as practicable after the later of the effective date of the Plan of Reorganization, or the date the CPUC decision approving the Settlement Agreement is no longer subject to appeal, the Utility will dismiss with prejudice its case against the CPUC Commissioners related to the federal filed rate doctrine, withdraw the original plan of reorganization and dismiss certain other pending proceedings. In exchange, the CPUC has established and authorized the collection of the Regulatory Asset and the Utility's rate base for its electricity generation, and, on or as soon as practicable after the effective date, the CPUC will resolve phase 2 of the pending Annual Transition Cost Proceeding, in which the CPUC is reviewing the reasonableness of the Utility's procurement costs incurred during the energy crisis, with no adverse impact on the Utility's requested cost recovery.
- On or as soon as practicable after the later of the effective date of the Plan of Reorganization or the date the CPUC decision approving the Settlement Agreement is no longer subject to appeal, PG&E Corporation, the Utility, and the CPUC will execute mutual releases and dismissals with prejudice of specified claims, actions, or regulatory proceedings arising out of or related in any way to the energy crisis or the implementation of Assembly Bill, or AB, 1890, including the CPUC's investigation into past holding company actions during the California energy crisis (but only as to past actions, not prospective matters).

Withdrawal of Applications in Connection with the Original Plan of Reorganization

As required by the Settlement Agreement, the Utility has requested a stay of all proceedings before the FERC, the NRC, the SEC and other regulatory agencies relating to approvals sought to implement the original plan of reorganization. The Utility also has suspended all actions to obtain or transfer licenses, permits and franchises to implement the original plan of reorganization. On the effective date of the Plan of Reorganization, or as soon thereafter as practicable, the Utility and PG&E Corporation will withdraw or abandon all applications for these

regulatory approvals. In addition, the Utility and PG&E Corporation have agreed that for the term of the Regulatory Asset, neither the Utility nor PG&E Corporation, nor their respective affiliates, will make any filings under Sections 4, 5 or 7 of the Natural Gas Act to transfer ownership or ratemaking jurisdiction over the Utility's intrastate gas pipeline and storage facilities, which means that these facilities will remain primarily subject to CPUC regulation. The Utility and PG&E Corporation have also agreed that the CPUC has jurisdiction to review and approve any proposal to dispose of the Utility's property necessary or useful in the performance of the Utility's duties to the public.

Environmental Measures

The Utility agreed to implement three environmental enhancement measures:

- The Utility will encumber with conservation easements or donate approximately 140,000 acres of land to public agencies or non-profit conservation organizations;
- The Utility will establish a California non-profit corporation to oversee the environmental enhancements associated with these lands and fund it with \$100 million in cash over ten years, although the Utility will be entitled to recover these payments in rates; and
- The Utility will create a non-profit corporation funded with \$30 million payable by the Utility over five years, with no recovery of these payments in rates, dedicated to support research and investment in clean energy technology, primarily in the Utility's service territory.

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.

Term and Enforceability

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 would have jurisdiction over the parties for all purposes relating to enforcement of the Settlement Agreement, the Plan of Reorganization and the confirmation order. 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.

Fees and Expenses

The Settlement Agreement requires the Utility to reimburse the CPUC for its professional fees and expenses incurred in connection with the Chapter 11 proceeding once the Plan of Reorganization is confirmed. These amounts will be recovered from customers over a reasonable time of up to four years. This accrual will be recorded when the applicable GAAP requirements are met. PG&E Corporation's professional fees and expenses incurred in connection with the Chapter 11 proceeding will not be reimbursed by the Utility or from the Utility's customers.

Financial Summary

Implementation of the Plan of Reorganization is subject to various conditions, including the consummation of the public offering of long-term debt, the receipt of investment grade credit ratings and final CPUC approval of the Settlement Agreement. Under the terms of the Plan of Reorganization PG&E Corporation and the Utility may determine that the CPUC order approving the Settlement Agreement is final even if appeals are pending. There can be no assurance that the Settlement Agreement will not be modified on rehearing or appeal or that the Plan of Reorganization will become effective. Until certain conditions or events regarding the effectiveness of the Plan of Reorganization discussed above are resolved further, PG&E Corporation and the Utility do not believe the applicable accounting probability standard under SFAS No. 71 needed to record the regulatory assets at December 31, 2003, has been met.

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,	
	2003	2002
(in millions)		
PG&E Corporation		
Loans due 2006, variable rate	\$ —	\$ 720
Senior secured notes, 6 7/8%, due 2008	600	—
Convertible subordinated notes, 9.50%, due 2010	280	280
Other long-term debt	3	—
Discount	—	(24)
Total long-term debt	883	976
Utility		
First and refunding mortgage bonds:		
5.85% to 8.80% bonds, maturing 2004-2026	2,764	3,044
Unamortized discount net of premium	(23)	(24)
Total mortgage bonds	2,741	3,020
Less: current portion	310	281
Total long-term debt, net of current portion	2,431	2,739
Total long-term debt, net of current portion	\$3,314	\$3,715
Long-term debt subject to compromise		
Senior notes, 10.38%, due 2005	680	680
Pollution control loan agreements, variable rates, due 2026	614	614
Pollution control loan agreement, 5.35%, due 2016	200	200
Unsecured medium-term notes, 6.56% to 9.20%, due 2004-2014	287	287
Deferrable interest subordinated debentures, 7.90%, due 2025	300	300
Other Utility long-term debt	17	19
Total long-term debt subject to compromise	\$2,098	\$2,100

PG&E Corporation

Senior Secured Notes

On July 2, 2003, PG&E Corporation completed a private placement of \$600 million of 6 7/8% Senior Secured Notes due July 15, 2008, or Senior Secured Notes. The net proceeds of the offering, approximately \$581 million, together with cash on hand, were used to repay the principal outstanding under PG&E Corporation's October 2002 credit agreement of approximately \$720 million, \$15 million of in-kind interest and a \$52 million prepayment premium. The payment resulted in the termination of PG&E Corporation's existing credit agreement and the release of liens on PG&E Corporation's shares of NEGT, as well as the prior lien on approximately 94% of the outstanding common stock of the Utility.

Interest is payable semi-annually in arrears on January 15 and July 15, commencing on January 15, 2004. The Senior Secured Notes are secured by a perfected first-priority security interest in approximately 94% of the outstanding common stock of the Utility that is owned by PG&E Corporation. With respect to 35% of such common stock pledged for the benefit of the lenders, the holders of the Senior Secured Notes have customary rights of a pledge of common stock, provided that certain regulatory approvals may be required in connection with any foreclosure on and

any exercise of the right to vote such stock. With respect to the remaining 65%, such common stock has been pledged for the benefit of the holders, but the holders have no ability to control such common stock under any circumstances and do not have any of the typical rights and remedies of a secured creditor. However, the holders do have the right to receive any cash distributions associated with such common stock.

The Senior Secured Notes are effectively subordinated to all indebtedness and other obligations (including trade payables) of PG&E Corporation's subsidiaries. In the event of a bankruptcy, liquidation or reorganization of any of PG&E Corporation's subsidiaries, such subsidiary will pay the holders of its debt and its trade creditors before it will be able to distribute any of its assets to PG&E Corporation.

PG&E Corporation may redeem all or a portion of the Senior Secured Notes at the following redemption premiums, plus accrued and unpaid interest.

Year	Percentage
Until July 15, 2006	106.875%
July 16, 2006 — July 15, 2007	103.438%
July 17, 2007 — July 15, 2008	101.719%

The indenture, among other restrictions, also prohibits PG&E Corporation from declaring or paying dividends unless it meets certain financial criteria or achieves an investment grade credit rating. Regardless of these restrictions, PG&E Corporation may pay a dividend from the proceeds of cash distributions from the Utility.

PG&E Corporation has agreed to have the Senior Secured Notes registered by June 26, 2004. If the Senior Secured Notes have not been registered by the specified date, the annual interest rate will increase by approximately 1% until they have been registered.

Convertible Subordinated Notes

On June 25, 2002, PG&E Corporation issued 7.50% Convertible Subordinated Notes, or Convertible Notes, due 2007 in the aggregate principal amount of \$280 million. The Convertible Notes may be converted by the holders into 18,558,655 shares of the common stock of PG&E Corporation.

Concurrent with the October 18, 2002 financing of the \$720 million credit agreement due in 2006, now paid in full, the indenture relating to the Convertible Notes was amended as follows:

- The cross default provisions related to NEGT and its subsidiaries was deleted;
- The interest rate on the Convertible Notes increased to 9.50% from 7.50%;
- The maturity of the Convertible Notes was extended from June 30, 2007 to June 30, 2010; and
- PG&E Corporation provided the holders of the Convertible Notes with a one-time right to require PG&E Corporation to repurchase the Convertible Notes on June 30, 2007 plus accrued and unpaid interest.

The holders of the Convertible Notes are also entitled to receive dividend payments as if they hold the common shares subject to the conversion feature.

Warrants

Concurrent with the negotiation of new terms and amendment to the 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, 2003, there were 4,353,113 of these warrants outstanding, of which 7,415 were subsequently exercised in January 2004.

Utility

The following information about the Utility's debt reflects the terms of the debt as of December 31, 2003. As discussed in Note 2 "The Plan of Reorganization," substantially all of this debt will be refinanced with the proceeds of a public offering of long-term debt, cash on hand and draws on credit facilities.



First and Refunding Mortgage Bonds

The Utility issued first and refunding mortgage bonds, or Mortgage Bonds, in various series that bear annual interest rates ranging from 5.85% to 8.80%. All real property and substantially all personal property of the Utility are subject to the lien of the mortgage, and the Utility is required to make semi-annual sinking fund payments for the retirement of the Mortgage Bonds. While in Chapter 11, the Utility is prohibited from making payments on the Mortgage Bonds without permission from the bankruptcy court. The bankruptcy court approved the payment of \$333 million of mortgage bonds that matured in March 2002 and \$281 million in August 2003, and has also approved the payment of interest in accordance with the terms of the Mortgage Bonds. In January 2004, the Utility filed a motion requesting that the bankruptcy court approve the payment of \$310 million of Mortgage Bonds maturing in March 2004.

Mortgage Bonds outstanding at December 31, 2003 and 2002 include \$345 million of bonds held in trust for the California Pollution Control Financing Authority, or CPCFA, with interest rates ranging from 5.85% to 6.63% and maturity dates ranging from 2009 to 2023.

Senior Notes

In November 2000, the Utility issued \$680 million of five-year senior notes, or Senior Notes, bearing an interest rate of 7.38%. The Utility used the net proceeds to repay short-term borrowings incurred to finance power purchases and for other general corporate purposes. These Senior Notes contain interest rate adjustments dependent upon the Utility's unsecured debt ratings.

As a result of the Utility's credit rating downgrades in January 2001, the interest rate on the Senior Notes was increased by 1.75%. In addition, in April 2001, an interest premium penalty of 0.5% was imposed due to the Utility's failure to make a public offering. As a result, the bankruptcy court approved a motion by various unsecured creditors increasing the interest rate on the Senior Notes to 9.63% effective November 1, 2000. The interest rate on the Senior Notes was increased by an additional 0.375% on February 15, 2003 and September 15, 2003 because a Utility plan of reorganization did not become effective on or before those dates. If the effective date of a plan of reorganization does not occur on or before March 15, 2004, the interest rate will increase by an additional 0.375%. In 2001, the Utility's Chapter 11 filing and failure to make payments on the Senior Notes were events of default. In 2002, the bankruptcy court authorized the Utility to make quarterly interest payments on these loans. The Senior Notes are classified as liabilities subject to compromise in the Consolidated Balance Sheets at December 31, 2003 and 2002.

Pollution Control Loan Agreements

Pollution control loan agreements, or Loans, held in trust for the CPCFA totaled \$814 million at December 31, 2003 and 2002. Interest rates on \$614 million of the Loans are variable. For 2003, the variable interest rates ranged from 0.75% to 1.31%. These Loans are subject to redemption by the holder under certain circumstances. They were secured primarily by irrevocable letters of credit from certain banks, which based on terms negotiated in 2002 and 2003, mature in 2004 through 2005. On March 1, 2001, \$200 million of the Loans were converted to a fixed rate obligation with an interest rate of 5.35% with credit supported by bond insurance. In 2002, the bankruptcy court authorized the Utility to make quarterly interest payments on the variable interest rate Loans and semiannual interest payments on the fixed interest rate Loans.

In April and May 2001, \$454 million of the Loans were accelerated and the banks paid the amounts due under the letters of credit, resulting in a reimbursement obligation from the Utility to the banks. The Utility had been unable to make principal or interest payments to the banks due to its Chapter 11 filing, an event of default, and accordingly amounts outstanding at December 31, 2003 and 2002, under the related loans are classified as liabilities subject to compromise in the Consolidated Balance Sheets at December 31, 2003 and 2002. In 2002, the bankruptcy court order authorized the Utility to make quarterly interest payments on these loans.

On the effective date of the Plan of Reorganization, the Utility may reinstate \$814 million of the Loans.

Unsecured Medium-Term Notes

The Utility has \$287 million of outstanding unsecured medium-term notes, or Medium-Term Notes, due from 2004 to 2014 with interest rates ranging from 6.56% to 9.20% at December 31, 2003. The Medium-Term Notes are also in default as the Utility has been unable to make interest and principal repayments on maturity due to its Chapter 11 proceeding. The interest rate on the Medium-Term Notes increased by an additional 0.375% on February 15, 2003 and September 15, 2003 because a plan of reorganization did not become effective on or before

those dates. The outstanding principal amounts of the Medium-Term Notes at December 31, 2003 and 2002 are classified as liabilities subject to compromise in the accompanying financial statements. In 2002, the bankruptcy court authorized the Utility to make quarterly interest payments on the Medium-Term Notes.

7.90% Deferrable Interest Subordinated Debentures

On November 28, 1995, PG&E Capital I, or Capital I, a wholly owned subsidiary of the Utility, issued 12 million shares of 7.90% Cumulative Quarterly Income Preferred Securities, or QUIPS, with a total liquidation value of \$300 million. Concurrent with the issuance of the QUIPS, Capital I issued to the Utility 371,135 shares of common stock securities with a total liquidation value of \$9 million. Capital I in turn used the net proceeds from the QUIPS offering and issuance of the common stock securities to purchase 7.90% Deferrable Interest Subordinated Debentures, or QUIDS, due 2025 issued by the Utility with a value of \$309 million at maturity.

The Utility's Chapter 11 filing on April 6, 2001, was an event of default under the trust agreement. On March 27, 2002, the bankruptcy court issued an order authorizing the Utility to pay pre- and post-petition interest to holders of certain undisputed claims, including the QUIDS, and on May 6, 2002, the Utility made payments representing interest accrued through February 28, 2002, which was then passed through by the trust to the holders of the QUIPS. Capital I was liquidated by the trustee under the terms of the trust agreement on May 24, 2002. Upon liquidation of Capital I, the holders of the QUIPS received a like amount of QUIDS after satisfaction of Capital I's liabilities to creditors. The terms and interest payments on the QUIDS correspond to the terms and dividend payments of the QUIPS.

The Utility has continued to make scheduled quarterly interest payments. The QUIDS are included in financing debt classified as liabilities subject to compromise on PG&E Corporation's and the Utility's Consolidated Balance Sheets at December 31, 2003 and 2002.

Repayment Schedule

At December 31, 2003, PG&E Corporation's and the Utility's combined aggregate amounts of maturing long-term debt as scheduled are reflected in the table below:

(in millions)	2004	2005	2006	2007	2008	Thereafter	Total
Expected maturity date							
PG&E Corporation	\$ —	\$ —	\$ —	\$ 3	\$600	\$ 280	\$ 883
Utility ⁽¹⁾:							
Long-term debt:							
Fixed rate obligations	310	289	—	—	—	2,142	2,741
Average interest rate	6.25%	5.88%	—	—	—	7.25%	6.99%
Liabilities subject to compromise:							
Fixed rate obligations	225	696	1	1	—	261	1,184
Average interest rate	8.16%	10.31%	9.45%	9.45%	—	6.10%	8.97%
7.90% Deferrable interest subordinated debentures	—	—	—	—	—	300	300
Variable rate obligations ⁽²⁾	349	265	—	—	—	—	614
Rate reduction bonds	290	290	290	290	—	—	1,160
Average interest rate	6.44%	6.42%	6.44%	6.48%	—	—	6.44%
Total	\$1,174	\$1,540	\$ 291	\$ 294	\$600	\$2,983	\$6,882

(1) Table is based upon contractual maturity dates

(2) The expected maturity dates for pollution control loan agreements with variable interest rates are based on the maturity dates of the letters of credit securing the loans.

Credit Facilities and Short-Term Borrowings

The following table summarizes the Utility's lines of credit. PG&E Corporation does not maintain credit facilities or short-term borrowings.

	December 31,	
	2003	2002
(in millions)		
Credit Facilities Subject to Compromise:		
5-year Revolving Credit Facility	\$ 938	\$ 938
Total Lines of Credit Subject to Compromise	938	938
Short-Term Borrowings Subject to Compromise:		
Bank Borrowings — Letters of Credit for Accelerated Pollution Control Agreement	454	454
Floating Rate Notes	1,240	1,240
Commercial Paper	873	873
Total Short-Term Borrowings Subject to Compromise	2,567	2,567
Total Credit Facilities and Short-Term Borrowings Subject to Compromise	\$3,505	\$3,505

Credit Facilities

At December 31, 2003 and 2002, the Utility had \$938 million outstanding on a defaulted \$1 billion five-year revolving credit facility. The bank terminated its outstanding commitment with the default. The interest rate on the revolving credit facility increased by an additional 0.375% on February 15, 2003 and September 15, 2003 because a plan of reorganization did not become effective on or before those dates. The weighted average interest rate was 8.75% at December 31, 2003 and 8.00% at December 31, 2002. This facility was used to support the Utility's commercial paper program and other liquidity requirements. The outstanding balance is classified as liabilities subject to compromise on the December 31, 2003 and 2002 Consolidated Balance Sheets. In 2002, the bankruptcy court authorized the Utility to make quarterly interest payments on these loans.

Bank Borrowing — Letters of Credit for Accelerated Pollution Control Bonds

As previously discussed, in April and May 2001 four pollution control loan agreements totaling \$454 million were accelerated by the note holders. These accelerations were funded by various banks under letter of credit agreements resulting in similar obligations from the Utility to the banks. The weighted average interest rate was 5.50% at December 31, 2003 and 5.75% at December 31, 2002.

Floating Rate Notes

The Utility issued a total of \$1.24 billion of 364-day floating rate notes in November 2000, with interest payable quarterly. The interest rate on the floating notes increased by an additional 0.375% on February 15, 2003 and September 15, 2003 because a plan of reorganization did not become effective on or before those dates. The weighted average interest rate was 8.33% at December 31, 2003 and 7.58% at December 31, 2002. These notes were not paid on the maturity date of October 31, 2001, resulting in an event of default. In 2002, an order by the bankruptcy court authorized the Utility to make quarterly interest payments on these loans.

Commercial Paper

The total amount of commercial paper outstanding at December 31, 2003 and 2002 was \$873 million. The Utility has been in default on its commercial paper obligations since January 17, 2001. The interest rate on the commercial paper increased by an additional 0.375% on February 15, 2003 and September 15, 2003, because a Utility plan of reorganization did not become effective on or before those dates. The weighted average interest rate on the Utility's commercial paper obligation was 8.22% at December 31, 2003 and was 7.47% at December 31, 2002. In 2002, an order by the bankruptcy court authorized the Utility to make quarterly interest payments on these loans.

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 2004 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 \$1.16 billion at December 31, 2003 and \$1.45 billion at December 31, 2002. The scheduled principal payments on the rate reduction bonds for the years 2004 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

On July 8, 2003, NEGT filed a voluntary petition for relief under Chapter 11. The decline in wholesale electricity prices, NEGT’s construction program, the decline of NEGT’s credit rating to below investment grade, and lack of market liquidity created severe financial distress and ultimately caused it to seek protection under Chapter 11. As a result of NEGT’s Chapter 11 filing and the elimination of equity ownership provided for in NEGT’s proposed plan of reorganization, PG&E Corporation considers its investment in NEGT to be an abandoned asset and has accounted for NEGT as discontinued operations in accordance with SFAS No. 144. Under the provisions of SFAS No. 144, the operating results of NEGT and its subsidiaries are reported as discontinued operations in the Consolidated Statements of Operations through July 7, 2003 and for all prior years.

Effective July 8, 2003, NEGT and its subsidiaries are no longer consolidated by PG&E Corporation in its Consolidated Financial Statements. The accompanying December 31, 2003 Consolidated Balance Sheet of PG&E Corporation does not reflect the separate assets and liabilities of NEGT; rather, a liability of approximately \$1.2 billion is reflected, which represents the losses of NEGT recognized by PG&E Corporation in excess of its investment in and advances to NEGT. In addition, accumulated other comprehensive income includes a net debit of approximately \$77 million at December 31, 2003 related to NEGT. PG&E Corporation’s investment in NEGT will not be affected by changes in NEGT’s future financial results, other than (1) investments in or dividends from NEGT, or (2) income taxes PG&E Corporation may be required to pay if the IRS disallows certain deductions or tax credits related to NEGT or its subsidiaries for past tax years that are incorporated into PG&E Corporation’s consolidated tax returns.

Upon implementation of NEGT’s plan of reorganization or another plan that eliminates PG&E Corporation’s equity in NEGT, PG&E Corporation will reverse its investment in NEGT and the related amounts included in deferred income taxes and in accumulated other comprehensive income and, as a result, recognize a material one-time net non-cash gain to earnings from discontinued operations. The deferred tax assets arising from the losses related to NEGT or its subsidiaries that have been recognized through July 7, 2003 will reverse at the time PG&E Corporation releases its ownership interest in NEGT. This reversal of deferred tax assets will partially offset any one-time gain recognized when PG&E Corporation recognizes the gain related to its net investment in NEGT.

NEGT Operating Results

Included within earnings from discontinued operations on the Consolidated Statements of Operations of PG&E Corporation are NEGТ's operating results, summarized below:

	188 Days Ended July 7,	Year Ended December 31,	Year Ended December 31,
(in millions)	2003	2002	2001
Operating revenues ⁽¹⁾	\$ 786	\$ 1,766	\$1,622
Income (Loss) before income taxes ⁽¹⁾	(595)	(4,094)	69

(1) Amounts shown have been adjusted for intercompany eliminations.

Before PG&E Corporation began accounting for NEGТ as discontinued operations, NEGТ 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 NEGТ 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 of NEGТ and its subsidiaries are impairments, write-offs, and other charges of approximately \$229 million.

The 2002 pre-tax loss of NEGТ 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 NEGТ and its subsidiaries are impairments, write-offs, and other charges of approximately \$2.8 billion.

During the second quarter of 2003, NEGТ 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, NEGТ 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 NEGТ by approximately \$843 million for the year ended December 31, 2002 and had no effect on the year ended December 31, 2001. In addition, adjustments were made principally for the effects of transactions that had not previously been eliminated in consolidation by NEGТ. Such adjustments decreased previously reported revenues and expenses by approximately \$671 million for the year ended December 31, 2002 and approximately \$1.1 billion for the year ended December 31, 2001. These changes did not result in any change in consolidated operating income or net income, in the Consolidated Statements of Operations.

NEGT Balance Sheet Information

The following table reflects the condensed assets and liabilities of NEGТ as reflected in current and noncurrent assets and liabilities in the accompanying Consolidated Balance Sheet of PG&E Corporation at December 31, 2002:

	Balance at December 31, 2002
(in millions)	
Assets	
Total current assets	\$3,029
Net property, plant and equipment	2,939
Total other non-current assets	1,944
Total assets	7,912
Liabilities	
Debt in default	4,230
Long-term debt, classified as current	17
Other current liabilities	2,410
Total current liabilities	6,657
Long-term debt	630
Price risk management	305
Other non-current liabilities and deferred credits	972
Total non-current liabilities	1,907
Total liabilities	8,564
Excess of liabilities over assets	\$ (652)

Commitments and Contingencies of NEGТ

With its Chapter 11 filings, NEGТ affiliates defaulted on numerous agreements. The amounts due as a result of these defaults will be determined and resolved in the context of NEGТ Chapter 11 filings. 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 416,520,282 shares were issued and outstanding at December 31, 2003 and 405,486,015 shares were issued and outstanding at December 31, 2002. A wholly owned subsidiary of PG&E Corporation holds 23,815,000 shares of the outstanding shares.

PG&E Corporation repurchased 34,037 shares of its common stock, at a cost of \$528,691 during the year ended December 31, 2001 and 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 416,520,282 shares issued and outstanding at December 31, 2003, 1,535,268 shares are PG&E Corporation restricted stock granted by the Board of Directors on January 2, 2003 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).

PG&E Corporation has issued warrants to purchase 5,066,931 shares of its common stock at an exercise price of \$0.01 per share to the lenders under prior credit agreements. At December 31, 2003, warrants to purchase 4,353,113 shares remained outstanding and were exercisable.

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, 2003 and 2002. A wholly owned subsidiary of the Utility holds 19,481,213 of the outstanding shares. PG&E Corporation and PG&E Holding, LLC, a subsidiary of the Utility, 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 has been pledged as security for PG&E Corporation's 6 7/8% Senior Secured Notes of \$600 million due 2008.

In October 2000, the Utility declared a \$110 million common stock dividend to PG&E Corporation and PG&E Holding, LLC. In January 2001, the Utility suspended payment of the declared dividend.

The Utility did not declare or pay common and preferred stock dividends in 2001, 2002 or 2003. Until cumulative dividends on its preferred stock and mandatory preferred sinking fund payments are paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

NOTE 7: PREFERRED STOCK

PG&E Corporation

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 has been issued or is outstanding.

Shareholder Rights Plan of PG&E Corporation

On December 20, 2000, the Board of Directors of PG&E Corporation declared a distribution of preferred stock purchase rights, or the Rights, at a rate of one Right for each share of PG&E Corporation common stock outstanding on January 2, 2001. The Board of Directors also authorized the issuance of one Right for each share of common stock issued by PG&E Corporation after January 2, 2001 and before the "distribution date" as described below. Each Right entitles the holder, in certain circumstances, to purchase from PG&E Corporation one one-hundredth of a share, or a Unit, of PG&E Corporation's Series A Preferred Stock, par value \$100 per share, at an initially fixed purchase price of \$95 per Unit, subject to adjustment.

The Rights are not exercisable until the distribution date. The distribution date will occur upon the earlier of (1) 10 days following a public announcement that a person or group (other than PG&E Corporation, any of its subsidiaries, or its employee benefit plans) has acquired or obtained the right to acquire beneficial ownership of 15% or more of the then-outstanding shares PG&E Corporation common stock and (2) 10 business days (or later, as determined by the Board of Directors) following the commencement of a tender offer or exchange offer that would result in a person or group owning 15% or more of the then-outstanding shares of PG&E Corporation common stock. After the distribution date, certain triggering events will enable the holder of each Right (other than a potential acquirer) to purchase Units of Series A Preferred Stock having twice the market value of the initially fixed exercise price, *i.e.*, at a 50% discount. Until a Right is exercised, the holder will not have any rights as a shareholder of PG&E Corporation, including without limitation the right to vote or to receive dividends.

As originally approved by the Board of Directors, the Rights would expire on December 22, 2010, unless redeemed earlier by the PG&E Corporation Board of Directors. On February 18, 2004, the Board of Directors adopted an amendment providing that the Rights will expire on the effective date of the Utility's Plan of Reorganization, unless otherwise redeemed earlier by the PG&E Corporation Board of Directors.

A total of 5,000,000 shares of preferred stock have been reserved for issuance upon exercise of the Rights. The Units of preferred stock that may be acquired upon exercise of the Rights will be non-redeemable and subordinate to any other shares of preferred stock that may be issued by PG&E Corporation. Each Unit of preferred stock will have a minimum preferential quarterly dividend rate of \$0.01 per Unit but will, in any event, be entitled to a dividend equal to the per share dividend declared on the common stock. In the event of liquidation, the holder of a Unit will receive a preferred liquidation payment.

The Rights also have certain anti-takeover effects and will cause substantial dilution to a person or group that attempts to acquire PG&E Corporation on terms not approved by PG&E Corporation's Board of Directors, unless the offer is conditioned on a substantial number of Rights being acquired. The Rights should not interfere with any approved merger or other business combination, as the Board of Directors, at its option, may redeem the Rights. Thus, the Rights are intended to encourage persons who may seek to acquire control of PG&E Corporation to initiate such an acquisition through negotiations with PG&E Corporation's Board of Directors.

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, 2003 and 2002, 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, 2003 and 2002, 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 its 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, 2003, 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, 2003, the Utility's redeemable preferred stock with mandatory redemption provisions consisted of 3 million shares of the 6.57% series and 2.5 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.

Due to the Utility's Chapter 11 proceeding, the Utility's Board of Directors has not declared or paid preferred stock dividends since January 31, 2001. 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. Accumulated and unpaid preferred stock dividends amounted to approximately \$80 million as of December 31, 2003, \$50 million as of December 31, 2002 and \$25 million as of December 31, 2001. 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.

As discussed above in Note 1 under "Adoption of New Accounting Policies — Accounting for Financial Instruments with Characteristics of Both Liabilities and Equity," 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 in the Utility's Consolidated Balance Sheets. The reclassification did not have an impact on earnings of PG&E Corporation or the Utility.

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.

Non-Trading Activities

On the Utility's Consolidated Balance Sheets, cash flow hedges associated with natural gas commodity price risk are presented at a fair value of \$4 million in other current assets. Unrealized losses associated with these cash flow hedges are recorded in regulatory accounts. The natural gas cash flow hedges have varying durations, the longest of which extend through March 2004.

Cash flow hedges associated with interest rate risk are presented at fair value in other current assets. For the portion of the cash flow hedges associated with regulated operations and subject to the provisions of SFAS No. 71, the effective and ineffective portions are recorded in regulatory assets. For the portion of hedges related to non-regulated

operations, the change in the fair value of the hedges is recorded in accumulated other comprehensive income and the ineffective portion of the change in the fair value is recorded in interest expense.

The following table presents selected information related to cash flow hedges associated with the interest rate risk related to non-regulated operations at December 31, 2003:

(in millions)	Fair Value on Balance Sheet	Accumulated Other Comprehensive Loss, Net of Tax	Portion Expected to be Reclassified to Earnings During the Next 12 Months	Maximum Term
Interest rate	\$ 17	\$ 3	—	June 2004

The actual amounts reclassified upon the contractual terms of the contracts or the termination of the hedge position will differ from the expected amounts presented above as a result of changes in interest rates. At December 31, 2002 the Utility did not have any cash flow hedges.

The ineffective portion of changes in amounts of the Utility's cash flow hedges was approximately \$4 million for the year ended December 31, 2003. There was no ineffective portion of changes in amounts of the Utility's cash flow hedges for the year ended December 31, 2002.

The Utility has certain non-trading derivative instruments for the purchase of electricity, natural gas and natural gas transportation and storage that are exempt from the SFAS No. 133 fair value requirements under the normal purchases and sales exception and thus have no mark-to-market effect on earnings. Additionally, the Utility holds an immaterial amount of other non-trading derivative instruments that do not qualify for cash flow hedge accounting or the normal purchase and sales exception to SFAS No. 133. These derivative instruments are reported in earnings on a mark-to-market basis.

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 \$2.5 billion at December 31, 2003 and \$2.0 billion at December 31, 2002. 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 \$68 million at December 31, 2003 and \$59 million at December 31, 2002 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 largest 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 2003 the Utility recognized no material losses due to contract defaults or bankruptcies. At December 31, 2003 there were three counterparties that represented greater than 10% of the Utility's net credit exposure. The Utility had two investment grade counterparties that represented a total of approximately 32% of the Utility's net credit exposure and one below-investment grade counterparty that represented approximately 12% of the Utility's net credit exposure.

The Utility conducts business with customers or vendors mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and 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.

The schedule below summarizes the Utility's net asset credit risk exposure, as well as the Utility's credit risk exposure to its largest customers or counterparties with a greater than 10% net credit exposure, at December 31, 2003 and December 31, 2002. Credit exposures to Enron subsequent to its filing for Chapter 11 are not included in the information below. See Note 12 for discussion of the Enron Settlement.

(in millions)	Gross Credit Exposure Before Credit Collateral ⁽¹⁾	Credit Collateral	Net Credit Exposure ⁽²⁾	Number of Largest Customer or Counterparties >10%	Net Exposure of Largest Customer or Counterparties >10%
December 31, 2003	\$165	\$ 11	\$154	3	\$ 68
December 31, 2002	288	113	175	2	55

(1) Gross credit exposure equals mark-to-market value, notes receivable and net receivables (payables) where netting is 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 incurred prior to the Utility's Chapter 11 filing 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 largest customers and counterparties at December 31, 2003 and December 31, 2002:

(in millions)	Net Credit Exposure ⁽²⁾	Percentage of Net Credit Exposure
Credit Quality ⁽¹⁾		
December 31, 2003		
Investment grade ⁽³⁾	\$108	70%
Non-investment grade	46	30%
Total	\$154	100%
December 31, 2002		
Investment grade ⁽³⁾	\$111	63%
Non-investment grade	64	37%
Total	\$175	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 quality.

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 2006 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 2003 dollars (or approximately \$5.25 billion in future dollars). These estimates are based on a 2002 decommissioning cost study, prepared in accordance with CPUC requirements and used in the Utility's Nuclear Decommissioning Costs Triennial Proceeding, which is 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. However, under GAAP requirements, the decommissioning cost estimate is calculated using a different method. As discussed above in Note 1 under "Adoption of New Accounting Policies — Accounting for Asset Retirement Obligations," on January 1, 2003 the Utility adopted SFAS No. 143, a GAAP requirement. Under SFAS No. 143, 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 (previously recorded in accumulated depreciation and decommissioning) on the Utility's Consolidated Balance Sheet. The total nuclear decommissioning obligation accrued in accordance with GAAP was approximately \$1.1 billion at December 31, 2003 and \$1.3 billion at December 31, 2002.

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. 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. The decision also set the annual decommissioning fund revenue requirement for Humboldt Bay Unit 3 at approximately \$18.5 million and granted the Utility's request to begin decommissioning Humboldt Bay Unit 3 in 2006 instead of 2015. The decision further granted the Utility's request of approximately \$8.3 million for Humboldt Bay Unit 3 SAFSTOR operating and maintenance costs, with escalation adjustments of approximately \$218,000 in 2004 and \$230,000 in 2005. SAFSTOR is 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 total adopted annual revenue requirement of approximately \$26.7 million represents a decrease of approximately \$4.5 million from the previously adopted revenue requirement of approximately \$31.2 million which included amounts for both Humboldt Bay Unit 3 and Diablo Canyon. The CPUC also ordered the Utility to partially fund its 2004 revenue requirement with approximately \$10 million that the Utility collected in rates in 2000 for its nuclear decommissioning revenue requirement, but that the Utility did not contribute to the trusts due to the Utility's cash conservation needs during the energy crisis.

The Utility's revenue requirements for nuclear decommissioning costs are recovered from ratepayers through a non-bypassable 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 ratepayers 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 2003, the Utility collected approximately \$22.6 million in rates and contributed approximately \$21.3 million, on an after-tax basis, to the nuclear decommissioning trusts. For 2004, the Utility is authorized to collect approximately \$18.5 million in rates for decommissioning Humboldt Bay Unit 3. Of this amount, the Utility expects to contribute approximately \$13.3 million, on an after-tax basis, to the qualified and non-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 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. The CPUC has authorized the CPUC 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 CPUC 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 range from 4.16% to 6.69% and in the non-qualified trusts to range from 3.79% to 5.97%. 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, 2003, the Utility had accumulated nuclear decommissioning trust funds with an estimated fair value of approximately \$1.4 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' current value.

The Utility accounts for its investments held in trusts as assets held for sale 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. Unrealized gains and losses are recorded in regulatory asset or liability accounts in accordance with SFAS No. 71.

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:

(in millions)	Maturity date	Total unrealized gains	Total unrealized losses	Fair value
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
Year ended December 31, 2002				
U.S. government and agency issues	2004-2032	\$ 50	\$ –	\$ 473
Municipal bonds and other	2004-2034	12	(1)	196
Equity securities		281	(9)	666
Total		\$343	\$(10)	\$1,335

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:

(in millions)	Year ended December 31,		
	2003	2002	2001
Proceeds received from sales of securities	\$1,087	\$1,631	\$751
Gross realized gains on sales of securities held as available-for-sale	27	51	71
Gross realized losses on sales of securities held as available-for-sale	(44)	(91)	(98)

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy, or 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. The DOE has been unable to meet its contractual commitment to begin accepting spent fuel. 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. At the projected level of operation for Diablo Canyon, the Utility's facilities are able to store on-site all spent fuel produced through approximately 2007. It is likely that an interim or permanent DOE storage facility will not be available for Diablo Canyon's spent fuel by 2007. Therefore, the Utility has applied to the NRC for authorization to store spent fuel in an on-site dry cask storage facility. The NRC has provided initial approval for the facility and is expected to complete its authorization process in early 2004. The Utility has also initiated the process to obtain the required California Coastal Commission permit for this facility. If the dry cask storage facility is not approved or is delayed, the Utility also is pursuing NRC approval of another storage option to install a temporary rack in each unit that would increase the on-site storage capability to permit the Utility to operate Unit 1 until 2010 and Unit 2 until 2011. During this additional period of time, the Utility also would pursue NRC approval for a high density reracking of both units, which, if approved, would allow the Utility to operate both units until shortly before the licenses expire in 2021 for Unit 1 and 2024 for Unit 2. 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 until such time as spent fuel can be safely stored.

NOTE 10: EMPLOYEE BENEFIT PLANS

PG&E Corporation and its subsidiaries provide non-contributory defined benefit pension plans for their 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, 2003. However, NEGT pension and other benefits information after December 31, 2002 is not disclosed below. PG&E Corporation and its subsidiaries use a December 31 measurement date for all of its 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 2003 and 2002:

Pension Benefits

(in millions)	PG&E Corporation		Utility	
	2003	2002	2003	2002
Projected benefit obligation at January 1	\$(6,738)	\$(6,091)	\$(6,732)	\$(6,047)
Service cost for benefits earned	(170)	(140)	(170)	(138)
Interest cost	(446)	(438)	(445)	(435)
Plan amendments	(135)	—	(135)	—
Actuarial loss	(338)	(418)	(338)	(409)
Settlement	4	1	4	1
Benefits and expenses paid	307	299	307	296
Projected benefit obligation at December 31	<u>\$(7,516)</u>	<u>\$(6,787)</u>	<u>\$(7,509)</u>	<u>\$(6,732)</u>
Accumulated benefit obligation	<u>\$(6,656)</u>	<u>\$(6,131)</u>	<u>\$(6,650)</u>	<u>\$(6,085)</u>

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 \$15 million at December 31, 2003 and \$10 million at December 31, 2002, and is recorded as a liability in PG&E Corporation's Balance Sheets.

Other Benefits

(in millions)	PG&E Corporation		Utility	
	2003	2002	2003	2002
Benefit obligation at January 1	\$(1,197)	\$(1,065)	\$(1,197)	\$(1,046)
Service cost for benefits earned	(29)	(25)	(29)	(25)
Interest cost	(79)	(77)	(79)	(76)
Actuarial loss	(61)	(107)	(61)	(99)
Participants paid benefits	(33)	(25)	(33)	(25)
Plan amendments	(124)	—	(124)	—
Benefits and expenses paid	79	74	79	74
Benefit obligation at December 31	<u>\$(1,444)</u>	<u>\$(1,225)</u>	<u>\$(1,444)</u>	<u>\$(1,197)</u>

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, 2003 and \$1 million at December 31, 2002, 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 2003 and 2002:

Pension Benefits

	PG&E Corporation		Utility	
	2003	2002	2003	2002
(in millions)				
Fair value of plan assets at January 1	\$6,153	\$7,175	\$6,153	\$7,132
Actual return on plan assets	1,280	(690)	1,280	(686)
Company contributions	7	11	7	11
Settlement	(4)	(8)	(4)	(8)
Benefits and expenses paid	(307)	(299)	(307)	(296)
Fair value of plan assets at December 31	\$7,129	\$6,189	\$7,129	\$6,153

Other Benefits

	PG&E Corporation		Utility	
	2003	2002	2003	2002
(in millions)				
Fair value of plan assets at January 1	\$749	\$ 914	\$749	\$ 899
Actual return on plan assets	186	(149)	186	(146)
Company contributions	72	50	72	48
Plan participant contributions	33	25	33	25
Benefits and expenses paid	(85)	(77)	(85)	(77)
Fair value of plan assets at December 31	\$955	\$ 763	\$955	\$ 749

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,	
(in millions)	2003	2002	2003	2002
Fair value of plan assets at December 31	\$ 7,129	\$ 6,189	\$ 7,129	\$ 6,153
Projected benefit obligation at December 31	(7,516)	(6,787)	(7,509)	(6,732)
Funded status plan assets less than projected benefit obligation	(387)	(598)	(380)	(579)
Unrecognized prior service cost	405	313	405	312
Unrecognized net loss	715	1,205	714	1,196
Unrecognized net transition obligation	8	22	8	22
Prepaid (accrued) benefit cost	\$ 741	\$ 942	\$ 747	\$ 951
Prepaid benefit cost	\$792	\$993	\$792	\$993
Accrued benefit liability	(51)	(51)	(45)	(42)
Additional minimum liability	(7)	(2)	(7)	(2)
Intangible asset	—	2	—	2
Accumulated other comprehensive income	7	—	7	—
Prepaid (accrued) benefit cost	\$741	\$942	\$747	\$951

Other Benefits

	PG&E Corporation		Utility	
	December 31,		December 31,	
(in millions)	2003	2002	2003	2002
Fair value of plan assets at December 31	\$ 955	\$ 763	\$ 955	\$ 749
Benefit obligation at December 31	(1,444)	(1,225)	(1,444)	(1,197)
Funded status plan assets less than benefit obligation	(489)	(462)	(489)	(448)
Unrecognized prior service cost	125	13	125	13
Unrecognized net loss	125	186	125	174
Unrecognized net transition obligation	232	261	232	257
Prepaid (accrued) benefit cost	\$ (7)	\$ (2)	\$ (7)	\$ (4)
Prepaid benefit cost	\$ —	\$ 8	\$ —	\$ —
Accrued benefit liability	(7)	(13)	(7)	(7)
Additional minimum liability	—	3	—	3
Prepaid (accrued) benefit cost	\$ (7)	\$ (2)	\$ (7)	\$ (4)

The separate prepaid benefit costs and accrued benefit liabilities of PG&E Corporation's pension and other benefit plans were as follows:

(in millions)	PG&E Corporation		Utility	
	December 31,		December 31,	
	2003	2002	2003	2002
Pension Benefits:				
Prepaid benefit cost	\$792	\$993	\$792	\$993
Accrued benefit liabilities	(51)	(51)	(45)	(42)
Other Benefits:				
Prepaid benefit cost	\$ –	\$ 8	\$ –	\$ –
Accrued benefit liabilities	(7)	(13)	(7)	(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 were as follows:

(in millions)	Pension Benefits		Other Benefits	
	December 31,		December 31,	
	2003	2002	2003	2002
PG&E Corporation:				
Projected benefit obligation	\$(7,516)	\$(6,787)	\$(1,444)	\$(1,225)
Accumulated benefit obligation	(6,656)	(6,131)	–	–
Fair value of plan assets	7,129	6,189	955	763
Utility:				
Projected benefit obligation	\$(7,509)	\$(6,732)	\$(1,444)	\$(1,197)
Accumulated benefit obligation	(6,650)	(6,085)	–	–
Fair value of plan assets	7,129	6,153	955	749

Components of Net Periodic Benefit Cost

Pension Benefits

(in millions)	PG&E Corporation			Utility		
	December 31,			December 31,		
	2003	2002	2001	2003	2002	2001
Service cost for benefits earned	\$ 170	\$ 140	\$ 128	\$ 170	\$ 138	\$ 127
Interest cost	446	438	420	445	435	417
Expected return on Plan's assets	(507)	(596)	(645)	(507)	(592)	(641)
Amortized prior service cost	56	59	55	56	59	55
Amortization of unrecognized loss	46	(3)	(83)	46	(3)	(82)
Settlement loss	1	5	–	1	5	–
Net periodic benefit cost (income)	\$ 212	\$ 43	\$(125)	\$ 211	\$ 42	\$(124)

Other Benefits

(in millions)	PG&E Corporation			Utility		
	December 31,			December 31,		
	2003	2002	2001	2003	2002	2001
Service cost for benefits earned	\$ 29	\$ 25	\$ 21	\$ 29	\$ 24	\$ 21
Interest cost	79	77	74	79	76	73
Expected return on Plan's assets	(61)	(76)	(83)	(61)	(75)	(82)
Amortized prior service cost	28	28	28	28	28	28
Amortization of unrecognized loss	1	(4)	(21)	1	(4)	(21)
Net periodic benefit cost (income)	\$ 76	\$ 50	\$ 19	\$ 76	\$ 49	\$ 19

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,		
	2003	2002	2001	2003	2002	2001
Discount rate	6.25%	6.75%	7.25%	6.25%	6.75%	7.25%
Average rate of future compensation increases	5.00%	5.00%	5.00%	—	—	—
Expected return on plan assets						
Pension Benefits	8.10%	8.10%	8.50%	—	—	—
Other Benefits:						
Defined Benefit — Medical Plan Bargaining	—	—	—	8.50%	8.50%	8.50%
Defined Benefit — Medical Plan Management	—	—	—	7.60%	7.20%	8.50%
Defined Benefit — Life Insurance Plan	—	—	—	8.50%	8.10%	8.50%

The assumed health care cost trend rate for 2004 is approximately 9.5%, grading down to an ultimate rate in 2008 and beyond of approximately 5.5%. 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	\$ 31	\$(28)
Effect on service and interest cost	3	(2)

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 8.5%.

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 2003, and below the expected return for 2002 and 2001.

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 annual accounting costs 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, 2003 and 2002, and target 2004 allocation was as follows:

	Pension Benefits			Other Benefits		
	2004	2003	2002	2004	2003	2002
Equity Securities						
U.S. Equity	40%	42%	39%	51%	50%	49%
Non-U.S. Equity	20	22	20	20	22	20
Debt Securities	40	36	41	29	28	31
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, 2003 and 2002 ranges from 1 to 46 years, with a weighted average maturity of 7 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 50% of the U.S. equity, 80% of the non-U.S. equity and virtually 100% of the debt security portfolios.

Cash Flow Information

PG&E Corporation and the Utility expect to contribute up to \$129 million to its Pension Benefits Plan, assuming favorable resolution of pension related rate recovery in the 2003 GRC, and approximately \$65 million to its Other Benefits Plan in 2004. 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 2004.

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. For certain plans, 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 once they have been credited to their account. Employer contribution expense reflected in PG&E Corporation's Consolidated Statements of Operations amounted to:

	(in millions)	
	PG&E Corporation	Utility
Year ended December 31,		
2003	\$ 38	\$ 37
2002	52	36
2001	48	33

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, 2003, a total of 40,130,988 shares of PG&E Corporation common stock had been authorized for award under the LTIP, with 12,714,608 shares still available for grant.

PG&E Corporation

The weighted average grant date fair values of options granted using the Black-Scholes valuation method were \$7.27 per share in 2003, \$6.60 per share in 2002, and \$6.01 and \$5.80 per share in 2001, using two sets of assumptions. Significant assumptions used in the Black-Scholes valuation method for shares granted in 2003, 2002, and 2001 (two sets of assumptions) were:

	2003	2002	2001
Expected stock price volatility	45.00%	30.00%	33.00% & 29.05%
Expected dividend yield	0.00%	0.00%	0.00% & 4.35%
Risk-free interest rate	3.46%	4.65%	5.24% & 5.95%
Expected life	6.5 years	10 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, 2003, had option prices ranging from \$11.80 to \$34.25, and a weighted average remaining contractual life of 6.13 years.

The following table summarizes stock option activity for the years ended December 31:

	2003		2002		2001	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding at January 1	31,067,611	\$22.22	34,080,405	\$22.11	24,342,794	\$25.90
Granted	3,649,902	14.62	211,712	19.44	11,407,152	14.33
Exercised	(3,818,837)	19.15	(332,436)	23.65	(132,499)	31.96
Cancelled	(3,482,296)	25.18	(2,892,070)	20.56	(1,537,042)	23.55
Outstanding at December 31	27,416,380	21.26	31,067,611	22.22	34,080,405	22.11
Exercisable	16,072,654	25.34	15,487,462	27.05	10,931,597	27.86

The following summarizes information for options outstanding and exercisable at December 31, 2003. Of the outstanding options at December 31, 2003:

- 11,436,557 options had exercise prices ranging from \$11.80 to \$16.68, with a weighted average remaining contractual life of 7.87 years, of which 2,177,155 shares were exercisable at a weighted average exercise price of \$14.51;
- 7,193,916 options had exercise prices ranging from \$19.45 to \$26.75, with a weighted average remaining contractual life of 5.41 years, of which 5,130,090 shares were exercisable at a weighted average exercise price of \$20.94; and
- 8,785,907 options had exercise prices ranging from \$27.13 to \$34.25, with a weighted average remaining contractual life of 4.46 years, of which 8,765,409 shares were exercisable at a weighted average exercise price of \$30.61.

In addition, 2,437,600 options were granted on January 2, 2004 at an exercise price of \$27.23, 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, 2003 had option prices ranging from \$12.63 to \$34.25, and a weighted average remaining contractual life of 6.19 years. The following table summarizes the stock option activity for the Utility employees for the years ended December 31:

	2003		2002		2001	
	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price	Shares	Weighted Average Option Price
Outstanding at January 1	13,300,300	\$22.32	13,601,834	\$22.35	9,414,899	\$26.68
Granted	2,160,425	14.62	—	—	4,404,700	14.32
Exercised	(1,310,156)	20.97	(187,935)	23.49	(129,999)	31.96
Cancelled	(607,387)	27.05	(113,599)	23.98	(87,766)	26.70
Outstanding at December 31	13,543,182	21.01	13,300,300	22.32	13,601,834	22.35
Exercisable	7,668,908	25.33	6,314,620	27.72	4,236,566	28.79

The following summarizes information for options outstanding and exercisable at December 31, 2003. Of the outstanding options at December 31, 2003:

- 5,995,290 options had exercise prices ranging from \$12.63 to \$16.68, with a weighted average remaining contractual life of 7.93 years, of which 1,113,239 options were exercisable at a weighted average exercise price of \$14.41;
- 3,210,388 options had exercise prices ranging from \$19.81 to \$26.31, with a weighted average remaining contractual life of 5.46 years, of which 2,218,165 options were exercisable at a weighted average exercise price of \$20.52; and
- 4,337,504 options had exercise prices ranging from \$28.35 to \$34.25, with a weighted average remaining contractual life of 4.33 years, of which 4,337,504 options were exercisable at a weighted average exercise price of \$30.59.

In addition, 1,638,500 options were granted to Utility employees on January 2, 2004 at an exercise price of \$27.23, the then-current market price of PG&E Corporation common stock.

Restricted Stock

On January 2, 2003, a total of 1,574,410 shares of restricted PG&E Corporation common stock was awarded to eligible employees of PG&E Corporation and its subsidiaries, of which 934,630 shares were granted 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.

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 \$7.1 million in 2003, of which approximately \$4.4 million 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 \$20 million at December 31, 2003. On January 2, 2004, PG&E Corporation awarded

495,900 shares of restricted stock, of which 333,110 shares were granted to Utility employees. For restricted stock grants awarded in 2004, the restrictions lapse ratably over four years.

Performance Units and Performance Shares

PG&E Corporation has granted performance units to certain officers and employees of PG&E Corporation and its subsidiaries. The performance units, subject to the 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. The number of performance units that were outstanding at December 31, 2003 was 318,256. The amount of compensation expense recognized in connection with the issuance of performance units was approximately \$11 million in 2003. The amount of compensation expense recognized in 2002 and 2001 was not material. No performance units were granted in 2004.

On January 2, 2004, PG&E Corporation awarded 495,900 performance shares, or phantom stock, of which 333,110 were awarded to Utility employees. The performance shares, subject to the achievement of certain performance targets, vest one-third per year and will be settled annually as vesting occurs in each of the three years following the date of the grant.

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. PG&E Corporation adjusts each employee's account on a quarterly basis and records additional compensation expense or income in its financial statements. Total compensation expense recognized by PG&E Corporation in connection with the plan amounted to approximately \$7 million for the year ended December 31, 2003, of which approximately \$1 million was recognized by the Utility. PG&E Corporation recognized compensation expense of approximately \$2 million for the year ended December 31, 2002, with no comparable amount for the Utility. For the year ended December 31, 2001 the compensation expense recognized in connection with the plan was not material.

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. 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:

	(in millions)	PG&E Corporation	Utility
Year ended December 31,			
2003		\$ 63	\$ 38
2002		12	7
2001		33	26

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,					
(in millions)	2003	2002	2001	2003	2002	2001
Current	\$102	\$ 713	\$ 931	\$ 695	\$ 838	\$ 902
Deferred	373	435	(284)	(150)	351	(267)
Tax credits, net	(17)	(11)	(39)	(17)	(11)	(39)
Income tax expense	\$458	\$1,137	\$ 608	\$ 528	\$1,178	\$ 596

The following describes net deferred income tax liabilities:

	PG&E Corporation		Utility	
	Year Ended December 31,			
	2003	2002	2003	2002
(in millions)				
Deferred Income Tax Assets:				
Customer advances for construction	\$ 386	\$ 318	\$ 386	\$ 318
Unamortized investment tax credits	110	105	110	105
Reserve for damages	273	268	273	268
Environmental reserve	172	162	172	162
Discontinued operations	605	1,162	—	—
Other	110	245	252	79
Total deferred income tax assets	\$1,656	\$2,260	\$1,193	\$ 932
Deferred Income Tax Liabilities:				
Regulatory balancing accounts	\$ 139	\$ 175	\$ 139	\$ 175
Property related basis differences	2,005	2,220	2,005	1,778
Income tax regulatory asset	142	134	142	134
Other	328	517	327	325
Total deferred income tax liabilities	2,614	3,046	2,613	2,412
Total net deferred income taxes liabilities	958	786	1,420	1,480
Classification of Net Deferred Income Taxes Liabilities:				
Included in current liabilities	102	4	86	(5)
Included in noncurrent liabilities	856	782	1,334	1,485
Total net deferred income taxes liabilities	\$ 958	\$ 786	\$1,420	\$1,480

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,					
	2003	2002	2001	2003	2002	2001
Federal statutory income tax rate	35.0%	35.0%	35.0%	35.0%	35.0%	35.0%
Increase (decrease) in income tax rate resulting from:						
State income tax (net of federal benefit)	4.7	5.3	4.6	4.9	5.4	5.0
Effect of regulatory treatment of depreciation differences	(2.9)	1.2	1.7	(2.5)	1.1	1.7
Tax credits, net	(1.7)	(0.5)	(2.5)	(1.5)	(0.5)	(2.5)
Other, net	1.3	(1.2)	(1.5)	0.5	(1.7)	(2.2)
Effective tax rate	36.4%	39.8%	37.3%	36.4%	39.3%	37.0%

At December 31, 2003, PG&E Corporation had \$420 million of California net operating loss, or NOL, carryforwards that will expire if not used by the end of 2012. The California Revenue and Taxation Code has suspended the use of NOL carryforwards for the tax years ending December 31, 2003 and December 31, 2002.

In 2002, PG&E Corporation established valuation allowances for state deferred tax assets associated with the impairments and write-offs related to NEGT and its subsidiaries. A valuation allowance of approximately \$184 million was recorded in discontinued operations with respect to state deferred tax assets associated with impairments and write-offs reflected in discontinued operations. These valuation allowances were established due to the uncertainty in realizing tax benefits associated with the state deferred tax assets. PG&E Corporation could not determine that it was more likely than not that some portion or all of its state deferred tax assets would be realized.

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.

Effective July 8, 2003, PG&E Corporation adopted the cost method of accounting for its ownership interest in NEGT. PG&E Corporation will not recognize additional income tax benefits for financial statement reporting purposes after July 7, 2003 with respect to any losses related to NEGT or its subsidiaries even though it continues to include NEGT and its subsidiaries in its consolidated income tax returns. Any such unrealized benefits and deferred tax assets arising from losses related to NEGT or its subsidiaries that have been recognized through July 7, 2003 will be recorded in discontinued operations in the Consolidated Statements of Operations at the time that PG&E Corporation releases its ownership interest in NEGT.

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 limited financial commitments relating to NEGT's operating activities.

Commitments

Utility

Power Purchase Agreements

Qualifying Facility 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. Under PURPA, the CPUC required California investor-owned electric utilities to enter into a series of long-term power purchase agreements with qualifying facilities and approved the applicable terms, conditions, price options 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 facility fails to meet or exceeds performance requirements specified in the applicable power purchase agreement.

As a result of the energy crisis, the Utility owed approximately \$1 billion to qualifying facilities when it filed its Chapter 11 petition. Through December 31, 2003, the principal payments made to the qualifying facilities amounted to \$998 million.

At December 31, 2003, the Utility had agreements with 300 qualifying facilities for approximately 4,400 megawatts, or MW, that are in operation. Agreements for approximately 4,000 megawatts expire between 2004 and 2028. Qualifying facility power purchase agreements for approximately 400 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 agreements with 50 qualifying facilities that are not currently providing or expected to provide electricity. The total of approximately 4,400 MW consists of approximately 2,600 MW from cogeneration projects, 800 MW from wind projects and 1,000 MW from other projects, including biomass, waste-to-energy, geothermal, solar and hydroelectric. On January 22, 2004, the CPUC adopted a decision that requires California investor-owned electric utilities to allow owners of qualifying facilities with power purchase agreements expiring before the end of 2005 to extend these contracts for five years. Qualifying facility power purchase agreements accounted for approximately 20% of the Utility's 2003 electricity sources, approximately 25% of the Utility's 2002 electricity sources, and approximately 21% of the Utility's 2001 electricity resources. No single qualifying facility accounted for more than 5% of the Utility's 2003, 2002 or 2001 electricity sources.

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 made to qualifying facilities. Under the Settlement Agreement, the net after-tax amount of any qualifying facilities refunds, which the Utility actually realizes in cash, claim offsets or other credits, would reduce the \$2.21 billion after-tax regulatory asset. While PG&E Corporation and the Utility are unable to estimate the outcome of this proceeding they believe the proceeding will not have a material adverse effect on their financial condition or results of operations.

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 2004 to 2031. The Utility's irrigation district and water agency contracts accounted for approximately 5% of 2003 electricity sources, approximately 4% of 2002 electricity sources and approximately 3% of 2001 electricity sources.

Other Power Purchase Agreements

Electricity Purchases to Satisfy the Residual Net Open Position – On January 1, 2003, the Utility resumed buying electricity to meet its residual net open position. During that year, more than 14,000 GWh of energy was bought and sold in the wholesale market to manage the 2003 residual net open position. Most of the Utility's contracts entered into in 2003 had terms of less than one year. During 2004 the Utility plans to enter into contracts of longer duration to satisfy its near-term residual net open position.

Renewable Energy Requirement – California law requires that, beginning in 2003, each California investor-owned electric utility 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 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 estimates the annual procurement target will initially require it to purchase about 750 Gigawatt-hours, or GWh, of electricity from renewable resources each year. The Utility met its 2003 commitment and the CPUC has approved several contracts intended to meet its 2004 renewable energy requirement.

Annual Receipts and Payments – The amount of electricity received and the total payments made under qualifying facility, irrigation district, water agency and bilateral agreements during 2001 through 2003 were as follows:

	2003	2002	2001
Gigawatt hours received	33,431	28,088	23,732
Qualifying facility energy payments (in millions)	\$ 994	\$ 1,051	\$ 1,454
Qualifying facility capacity payments (in millions)	499	506	473
Irrigation district and water agency payments (in millions)	62	57	54
Other power purchase agreement payments (in millions)	513	196	155

At December 31, 2003, the undiscounted future expected power purchase agreement payments were as follows:

(in millions)			Irrigation District & Water Agency				Total
	Qualifying Facility		Operations & Maintenance	Debt Service	Other		
	Energy	Capacity			Energy	Capacity	
2004	\$ 1,070	\$ 520	\$ 41	\$ 28	\$ 60	\$ 36	\$ 1,755
2005	1,040	520	35	26	27	36	1,684
2006	1,020	510	31	26	27	36	1,650
2007	970	490	30	26	28	35	1,579
2008	940	480	31	26	14	8	1,499
Thereafter	8,300	4,100	182	142	79	49	12,852
Total	\$13,340	\$6,620	\$350	\$274	\$235	\$200	\$21,019

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.

As a result of the Utility's Chapter 11 filing and its credit rating being below investment grade, it uses 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. The core natural gas inventory also may be pledged, but only if the amount of the Utility's natural gas customer accounts receivable is less than the amount that it owes to natural gas suppliers. To date, the Utility's accounts receivable pledge has been sufficient. The pledged amounts were approximately \$561 million at December 31, 2003 and \$513 million at December 31, 2002. It is anticipated that the pledge of natural gas customer accounts receivable and natural gas inventory will be replaced with letters of credit no later than the effective date of the Plan of Reorganization.

The Utility also has long-term gas transportation service agreements with various Canadian and interstate pipeline companies. These companies are responsible for transporting the Utility's gas to the California border. These agreements include provisions for payment of fixed demand charges for reserving firm pipeline capacity as well as volumetric transportation charges. The total demand charges that the Utility will pay each year may change periodically as a result of changes in regulated tariff rates. The total demand (net of sales of excess supplies) and volumetric transportation charges the Utility incurred under these agreements were approximately \$131 million in 2003, \$101 million in 2002 and \$239 million in 2001.

At December 31, 2003, the Utility's obligations for natural gas purchases and gas transportation services were as follows:

	(in millions)
2004	\$ 852
2005	115
2006	26
2007	7
2008	—
Thereafter	—
Total	\$1,000

Nuclear Fuel Agreements

The Utility has purchase agreements for nuclear fuel. These agreements have terms ranging from two to five years and are intended to ensure long-term fuel supply. Deliveries under nine of the eleven contracts in place at the end of 2003 will end by 2005. 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 commitments and provide security of supply. Pricing terms are also diversified, ranging from fixed prices to base prices that are adjusted using published information.

At December 31, 2003, the undiscounted obligations under nuclear fuel agreements were as follows:

	(in millions)
2004	\$ 90
2005	12
2006	13
2007	14
2008	13
Thereafter	52
Total	\$194

Payments for nuclear fuel amounted to approximately \$57 million in 2003, \$70 million in 2002 and \$50 million in 2001.

WAPA Commitments

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 give the Utility access to WAPA's excess hydroelectric power and obligate the Utility to provide WAPA with electricity when its own resources are not sufficient to meet its requirements. The contracts are scheduled to terminate on December 31, 2004, but termination is subject to FERC approval, which the Utility expects to receive.

The costs to fulfill the Utility's obligations to WAPA under the contracts cannot be accurately estimated at this time since both the purchase price and the amount of electricity WAPA will need from the Utility in 2004 are uncertain. However, the Utility expects that the cost of meeting its contractual obligations to WAPA will be greater than the price the Utility receives from WAPA under the contracts. Although it is not indicative of future sales commitments or sales-related costs, WAPA's net amount purchased from the Utility was approximately 4,804 GWh, in 2003, 3,619 GWh in 2002 and 4,823 GWh in 2001.

Transmission Control Agreement

The Utility is a party to a Transmission Control Agreement, or TCA, with the ISO and other participating transmission owners. As a transmission owner, the Utility is required to give two years notice and receive regulatory approval if it wishes to withdraw from the TCA. Under this agreement, the transmission owners, which also include Southern California Edison, or SCE, San Diego Gas & Electric Company and several municipal utilities, assign operational control of their electricity transmission systems to the ISO. In addition, as a party to the TCA, the Utility is responsible for a share of the costs of reliability must-run, or RMR, agreements between the ISO and owners of the power plants subject to RMR agreements, or RMR Plants. The Utility also is an owner of some of these RMR Plants for which the Utility receives revenue from the ISO. Under the RMR agreements, RMR Plants must remain available to generate electricity when needed for local transmission system reliability upon the ISO's demand.

At December 31, 2003, the ISO had RMR agreements for which the Utility could be obligated to pay the ISO an estimated \$446 million in net costs during the period January 1, 2004 to December 31, 2005. These costs are recoverable under applicable ratemaking mechanisms.

It is possible that the Utility may receive a refund of RMR costs that the Utility previously paid to the ISO. In June 2000, a FERC administrative law judge issued an initial decision approving rates that, if affirmed by the FERC, would require the subsidiaries of Mirant Corporation, or Mirant, 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 \$340 million, including interest, for availability of Mirant's RMR Plants under these agreements. However, 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. The Utility is unable to predict at this time when the FERC will issue a final decision on this issue, what the FERC's decision will be, and the amount of any refunds, which may be impacted by Mirant's Chapter 11 filing. It is uncertain how the resolution of this matter would be reflected in rates.

Other Commitments

The Utility has other commitments relating to operating leases, capital infusion agreements, equipment replacements, software licenses, the self-generation incentive program exchange agreements and telecommunication contracts. At December 31, 2003, the future minimum payments related to other commitments were as follows:

	(in millions)
2004	\$126
2005	48
2006	30
2007	15
2008	14
Thereafter	5
Total	\$238

Contingencies

PG&E Corporation

NEGT and its creditors have filed a complaint against PG&E Corporation and two PG&E Corporation officers who previously served on NEG's Board of Directors, in NEG's Chapter 11 proceeding, asserting, among other claims, that NEG is entitled to be compensated under an alleged tax sharing agreement between PG&E Corporation and NEG for any tax savings achieved by PG&E Corporation as a result of the incorporation of the losses and deductions related to NEG or its subsidiaries in PG&E Corporation's consolidated federal income tax return. In May 2003, PG&E Corporation received a return of \$533 million from the IRS for an overpayment of 2002 estimated federal income taxes. In November 2003, NEG and its creditors amended their complaint to add additional causes of action arising out of or related to the filing by PG&E Corporation of its 2002 federal consolidated tax return, and certain restructuring negotiations that occurred between PG&E Corporation and certain creditors of NEG's prior to NEG's Chapter 11 filing, including claims for breach of contract, breach of fiduciary duty, violation of the automatic stay, turnover, an accounting, unjust enrichment, fraudulent transfer, constructive trust, breach of standstill agreement, deceit equitable subordination and indemnification. NEG and the creditors' committees seek a declaration that an

implied tax sharing agreement exists between PG&E Corporation and NEGT as well as injunctive relief prohibiting PG&E Corporation from taking certain tax positions on its consolidated tax returns in the future. The complaint also alleges a cause of action for breach of fiduciary duty against two PG&E Corporation officers who previously served on NEGT's Board of Directors. NEGT and its creditors recently agreed to dismiss the equitable subordination and indemnification claims without prejudice.

NEGT and its creditors have asserted that they have a direct interest in certain tax savings achieved by PG&E Corporation and are entitled to be paid approximately \$414 million of the funds received by PG&E Corporation (approximately \$361.5 million achieved by the incorporation of losses and deductions related to NEGT or its subsidiaries and approximately \$53 million achieved by the incorporation of certain tax credits related to one of NEGT's subsidiaries). In addition to at least \$414 million in damages, the plaintiffs seek punitive damages against PG&E Corporation for deceit, as well as interest, costs of suit, and reasonable attorney's fees.

Defendants have filed a motion in the U.S. District Court of Maryland seeking to transfer the litigation from the bankruptcy court to the District Court. The District Court has scheduled a hearing date of April 22, 2004 for this motion.

Defendants also have filed a motion in the bankruptcy court to dismiss the complaint while awaiting a decision from the District Court. A hearing on this motion has been set for March 25, 2004. In the meantime, the bankruptcy court has set a trial date for January 2005.

PG&E Corporation denies that any tax sharing agreement, whether implied or expressed, ever existed and denies that it has any obligation to compensate NEGT for the incorporation of losses, deductions and tax credits related to NEGT or its subsidiaries into PG&E Corporation's consolidated federal tax returns, as required under the Internal Revenue Code. Until the dispute is resolved, PG&E Corporation is treating \$361.5 million as restricted cash included in noncurrent other assets on PG&E Corporation's Consolidated Balance Sheet at December 31, 2003. PG&E Corporation anticipates continuing to incorporate losses, deductions and certain tax credits related to NEGT or its subsidiaries in PG&E Corporation's consolidated income tax return, until it is no longer consolidated for federal income tax purposes. NEGT and its creditors have asserted that NEGT should be compensated for any such tax savings.

PG&E Corporation does not expect that the outcome of this matter will have a material adverse effect on its results of operations, financial position or liquidity.

As further disclosed below, PG&E Corporation has guaranteed the Utility's reimbursement obligation associated with certain surety bonds and the Utility's obligation to pay workers' compensation claims.

Utility

2003 General Rate Case Settlement and Generation Settlement

The CPUC determines the amount of authorized base revenues the Utility can collect from customers to recover its basic business and operational costs for electricity and natural gas distribution operations and for electricity generation operations in a GRC. The Utility's last GRC was its 1999 GRC, approved by the CPUC in 2000. The 2003 GRC has been filed, testimony has been given before the CPUC and the Utility is awaiting a final decision. Any revenue requirement change resulting from a final decision will be retroactive to January 1, 2003.

In July 2003, the Utility and various intervenors (The CPUC's Office of Ratepayer Advocates, or ORA, TURN, Aglet Consumer Alliance, and the City and County of San Francisco) filed a joint motion with the CPUC seeking approval of a settlement agreement resolving specific issues related to the cost of operating the Utility's electricity generation facilities, or the generation settlement. In September 2003, the Utility and various intervenors (ORA, TURN, Aglet Consumer Alliance, the Modesto Irrigation District, the Natural Resources Defense Council and the Agricultural Energy Consumers Association) filed a joint motion with the CPUC seeking approval of the GRC settlement. The GRC settlement, together with the generation settlement, resolves all disputed economic issues among the settling parties related to the Utility's electricity distribution, natural gas distribution, and generation revenue requirements, with the exception of the Utility's request that the CPUC include the costs of a pension contribution in the Utility's revenue requirement. The CPUC will resolve the pension contribution issue, as well as other issues raised by non-settling intervenors, in its final decision. The CPUC agreed in the Settlement Agreement to act promptly on the 2003 GRC.

The GRC settlement would result in a total 2003 revenue requirement of approximately \$2.5 billion for electricity distribution operations, representing a \$236 million increase in the Utility's electricity distribution revenue

requirement over the current authorized amount. The GRC settlement provides that the electricity distribution rate base on which the Utility would be entitled to earn an authorized rate of return would be approximately \$7.7 billion, based on recorded 2002 plant, and including net weighted average capital additions for 2003 of approximately \$292 million.

The GRC settlement also would result in a total 2003 revenue requirement of approximately \$927 million for the Utility's natural gas distribution operations, representing an approximately \$52 million increase in the Utility's natural gas distribution revenue requirement over the current authorized amount. The GRC settlement also provides that the amount of natural gas distribution rate base on which the Utility would be entitled to earn an authorized rate of return would be approximately \$2.1 billion, based on recorded 2002 plant, and including weighted average capital additions for 2003 of approximately \$89 million.

Together with the generation settlement, the GRC settlement would result in a 2003 generation revenue requirement of approximately \$912 million representing an increase of approximately \$38 million in the Utility's generation revenue requirement over the current authorized amount. This generation revenue requirement excludes fuel expense, the cost of electricity purchases, the DWR revenue requirements and nuclear decommissioning revenue requirements. Under the Settlement Agreement, the Utility's adopted 2003 generation rate base of approximately \$1.6 billion would be deemed just and reasonable by the CPUC and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. This reaffirmation of the Utility's electricity generation rate base would allow recognition of an after-tax regulatory asset of approximately \$800 million (or approximately \$1.3 billion pre-tax) as estimated at December 31, 2003. The Utility expects to record this regulatory asset when it meets the probability requirements for regulatory recovery in rates as provided for in SFAS No. 71. The individual components of the regulatory asset will be amortized over their respective lives. The weighted average life of these individual components is approximately 16 years.

The GRC settlement also provides for new balancing accounts to be established retroactive to January 1, 2004, that permit the Utility to recover its authorized electricity distribution and generation revenue requirements regardless of the level of sales. If sales levels do not generate revenues equal to the full revenue requirement in a period, rates in subsequent periods will be increased to collect the shortfall. Similarly, future rates will decrease if sales levels generate more than the full revenue requirement.

If the Utility prevails on the pension contribution issue, an additional revenue requirement of approximately \$75 million would be allocated among electricity distribution, natural gas distribution and electricity generation operations.

Because the CPUC has yet to issue a final decision on the Utility's 2003 GRC, the Utility has not included the natural gas distribution revenue requirement increase in its 2003 results of operations. If the CPUC approves a 2003 revenue requirement increase in 2004, the Utility would record both the 2003 and 2004 natural gas distribution revenue requirement increase in its 2004 results of operations.

In 2003 the Utility collected electricity revenue and surcharges subject to refund under the frozen rate structure. The amount of electricity revenue subject to refund pursuant to the rate design settlement in 2003 was \$125 million, which incorporates the impact of the electric portion of the GRC settlement. The Utility has recorded a regulatory liability for such amount. If the revenue requirement that is ultimately approved in the Utility's 2003 GRC is lower than the amounts described above, the regulatory liability would increase.

The CPUC also is considering a proposed reliability performance incentive mechanism for the Utility that would be in effect from 2004 through 2009. Under the proposed incentive mechanism, the Utility would receive up to \$27 million in additional annual revenues to be recorded in a one-way balancing account to be spent exclusively on reliability performance activities with a goal of decreasing the duration and frequency of electricity outages. The Utility would be entitled to earn a maximum reward of up to \$42 million each year depending on the extent to which the Utility exceeded the reliability performance improvement targets. Conversely, the Utility would be required to pay a penalty of up to \$42 million a year depending on the extent to which it failed to meet the target.

On February 3, 2004, the CPUC reopened the 2003 GRC record for the purpose of taking further evidence regarding executive compensation and bonuses. The Utility has filed a report addressing these issues with the CPUC. PG&E Corporation and the Utility are uncertain how this matter will be resolved and when a final GRC decision will be issued.

If the GRC settlement is not approved by the CPUC, the Utility's ability to earn its authorized rate of return for the years until the next GRC would be adversely affected. The parties to the GRC settlement have agreed that the Utility's next GRC will determine rates for test year 2007. The Utility is unable to predict the outcome of the 2003 GRC or the impact it will have on its financial condition or results of operations.

Surcharge Revenues

In January 2001, the CPUC authorized increases in electricity rates of \$0.01 per kilowatt-hour, or kWh, in March 2001 of another \$0.03 per kWh and in May 2001 of an additional \$0.005 per kWh. The use of these surcharge revenues was restricted to “ongoing procurement costs” and “future power purchases.” In November and December 2002, the CPUC approved decisions modifying the restrictions on the use of revenues generated by the surcharges and authorizing the surcharges to be used to restore the Utility’s financial health by permitting the Utility to record amounts related to the surcharge revenues as an offset to unrecovered transition costs. From January 2001 to December 31, 2003, the Utility recognized total surcharge revenues subject to refund of approximately \$8.1 billion, pre-tax. The rate design settlement includes a refund of approximately \$125 million of surcharge revenues. Accordingly, at December 31, 2003, the Utility had recorded a regulatory liability for potential refund of approximately \$125 million of surcharge revenues collected in 2003. In addition, if the CPUC requires the Utility to refund any amounts in excess of \$125 million, the Utility’s earnings could be materially adversely affected.

PX Block-Forward Contracts

The Utility had PX block-forward contracts, which were seized by California 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 plaintiff’s valuations. This state court litigation is pending.

FERC Prospective Price Mitigation Relief

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 January 2000 to June 2001. In December 2002, a FERC administrative law judge issued an initial decision 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 (the only time period for which the FERC permitted refund claims), but that California buyers still owe the power suppliers approximately \$3.0 billion, leaving approximately \$1.2 billion in net unpaid bills.

During 2003, the FERC confirmed most of the administrative law judge’s findings, 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 has indicated that it plans to make its compliance filing by August 2004. The actual refunds will not be determined until the FERC issues a final decision, following the ISO and PX compliance filings. The FERC is uncertain when it will issue a final decision in this proceeding. In addition, future refunds could increase or decrease as a result of an alternative calculation proposed by the ISO, which incorporates revised data provided by the Utility and other entities.

Under the Settlement Agreement, the Utility and PG&E Corporation agreed to continue to cooperate with the CPUC and the State of California in seeking refunds from generators and other energy suppliers. The net after-tax amount of any refunds, claim offsets or other credits from generators or other energy suppliers relating to the Utility’s ISO, PX, qualifying facilities or energy service provider costs that are actually realized in cash or by offset of creditor claims in its Chapter 11 proceeding would reduce the balance of the \$2.21 billion after-tax regulatory asset created by the Settlement Agreement.

The Utility has 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. The Utility currently estimates that the claims filed would have been reduced to approximately \$1.2 billion based on the refund methodology recommended in the administrative law judge’s initial decision, resulting in a net liability of approximately \$1.0 billion after the approximately \$200 million pre-petition offset. The recalculation of market prices according to the revised methodology adopted by the FERC in its October 2003 decision could further reduce the amount of the suppliers’ claims by several hundred million dollars. However 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.

Nuclear Insurance

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 additional annual premiums of up to \$36.7 million.

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 \$10.9 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 \$10.9 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 reactors 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 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, that 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. The Utility must deposit collateral with the California Department of Industrial Relations, or DIR, to maintain its status as a self-insurer for workers' compensation claims made against the Utility. Acceptable forms of collateral include surety bonds, letters of credit, cash and securities. At December 31, 2003, the Utility provided collateral in the form of \$305 million in surety bonds and approximately \$43 million in a cash deposit.

In February 2001, several surety companies provided cancellation notices because of the Utility's financial situation. The cancellation of these bonds has not impacted the Utility's self-insured status under California law. The DIR has not agreed to release the canceling sureties from their obligations for claims occurring before the cancellation and has continued to apply the canceled bond amounts, totaling \$185 million, toward the \$348 million collateral requirement. At December 31, 2003, the Utility's \$348 million in collateral consisted of the \$185 million in cancelled bonds, \$120 million in active surety bonds and approximately \$43 million in cash. PG&E Corporation has guaranteed the Utility's reimbursement obligation associated with these surety bonds and the Utility's underlying obligation to pay workers' compensation claims.

El Paso Settlement

In June 2003, the Utility, along with a number of other parties, entered into the El Paso settlement, which resolves all potential and alleged causes of action against El Paso for its part in alleged manipulation of natural gas and electricity commodity and transportation markets during the period from September 1996 to March 2003. Under the El Paso settlement, El Paso will pay approximately \$1.5 billion in cash and non-cash consideration, of which approximately \$550 million is now in an escrow account and approximately \$875 million will be paid over 15 to 20 years. The Utility's share of the approximately \$1.5 billion settlement is approximately \$300 million. El Paso also agreed to a approximately \$125 million reduction in El Paso's long-term electricity supply contracts with the DWR, to provide pipeline capacity to California and to ensure specific reserve capacity for the Utility, if needed. In October

2003, the CPUC approved an allocation of these refunds, under which the Utility's natural gas customers would receive approximately \$80 million and its electricity customers would receive approximately \$216 million. The settlement was approved by the FERC in November 2003 and by the San Diego Superior Court in December 2003. At least one appeal of the San Diego Superior Court's approval has been filed; however, the Utility believes that it is probable that the El Paso settlement will not be overturned on appeal.

Enron Settlement

On December 23, 2003, the Utility entered into a settlement agreement with five subsidiaries of Enron Corporation, or Enron, settling certain claims between the Utility and Enron, or the Enron settlement. The Enron settlement will become effective if approved by the bankruptcy courts overseeing both the Utility's and Enron's Chapter 11 proceedings. A hearing for approval of the Enron settlement is currently scheduled in the Utility's Chapter 11 proceeding on March 5, 2004. A hearing was held in the Enron bankruptcy court on February 5, 2004 and the matter was submitted. If the Enron settlement is approved, the Utility will receive an after-tax credit of approximately \$90 million that will reduce the \$2.21 billion after-tax regulatory asset as called for in the Settlement Agreement. In its January 26, 2004 filing with the CPUC proposing an electricity rate reduction, the Utility has reduced the revenue requirement related to the \$2.21 billion after-tax regulatory asset to reflect this after-tax credit.

DWR Contracts

The DWR provided approximately 30% of the electricity delivered to the Utility's customers for the year ended December 31, 2003. The DWR purchased the electricity under contracts with various generators and through open market purchases. 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. The DWR remains legally and financially responsible for the electricity procurement contracts.

The 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.

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 \$314 million at December 31, 2003 and approximately \$331 million at December 31, 2002. During 2003, the liability was reduced by approximately \$17 million mainly due to reassessment of the estimated cost of remediation and remediation payments. The approximately \$314 million accrued at December 31, 2003 includes approximately \$104 million related to the pre-closing remediation liability associated with divested generation facilities and approximately \$210 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 \$314 million environmental remediation liability, approximately \$147 million has been included in prior rate setting proceedings and the Utility expects that approximately \$116 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 ratepayers.

The Utility's undiscounted future costs could increase to as much as \$422 million if the other potentially responsible parties are not financially able to contribute to these costs, or the extent of contamination or necessary remediation is greater than anticipated. The approximately \$422 million amount 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 liability exists.

The California Attorney General, on behalf of various state environmental agencies, filed claims in the Utility's Chapter 11 proceeding for environmental remediation at numerous sites totaling approximately \$770 million. For most of these sites, remediation is ongoing in the ordinary course of business or the Utility is in the process of remediation in cooperation with the relevant agencies and other parties responsible for contributing to the clean-up. Other sites identified in the California Attorney General's claims may not, in fact, require remediation or clean-up actions. The Utility's Plan of Reorganization provides that the Utility intends to respond to these types of claims in the ordinary course of business, and since the Utility has not argued that the Chapter 11 proceeding relieves the Utility of its obligations to respond to valid environmental remediation orders, the Utility believes the California Attorney General's claims seeking specific cash recoveries are unenforceable. Environmental claims in the ordinary course of business will not be discharged in the Utility's Chapter 11 proceeding and will pass through the Chapter 11 proceeding unimpaired.

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. The Utility's Chapter 11 filing on April 6, 2001, discussed in Note 2, automatically stayed the litigation described below against the Utility, except as otherwise noted.

Chromium Litigation

There are 14 civil suits pending against the Utility in several California state courts. 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 have filed proofs of claims with the bankruptcy court, most of whom are plaintiffs in the 14 chromium litigation cases. Approximately 1,035 of these claimants have filed proofs of claim requesting an approximate aggregate amount of \$580 million and approximately another 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 compressor stations at Hinkley and Kettleman, 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' motion 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 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 13 summary judgment motions or motions in limine, which are motions to exclude potentially prejudicial information, challenging the claims of the trial test plaintiffs. Two of the 13 summary judgment motions are scheduled for hearing in February 2004. The trial of the test cases is scheduled to begin in March 2004. The Utility also has filed a motion to dismiss the complaint in one of the cases. After a hearing in November 2003, the motion to dismiss was granted. The plaintiffs in that case have until March 2004 to file an amended complaint.

The Utility has recorded a \$160 million reserve in its financial statements for these matters. PG&E Corporation and the Utility believe that, after taking into account the reserves recorded at December 31, 2003, 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, "Accounting for Contingencies," 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.

The provision 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 \$205 million at December 31, 2003 and \$202 million at December 31, 2002.

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

	Quarter Ended			
	December 31	September 30	June 30	March 31
(in millions, except per share amounts)				
2003 ⁽¹⁾				
PG&E CORPORATION				
Operating revenues ^{(1) (2)}	\$ 2,538	\$3,103	\$2,729	\$2,065
Operating income ⁽¹⁾	317	1,173	780	73
Income (loss) from continuing operations ⁽¹⁾	37	508	328	(82)
Net income (loss) ⁽⁴⁾	37	510	227	(354)
Earnings (Loss) per common share from continuing operations, basic	0.10	1.31	0.85	(0.21)
Earnings (Loss) per common share from continuing operations, diluted	0.09	1.24	0.81	(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 ⁽²⁾	\$ 2,538	\$3,103	\$2,730	\$2,067
Operating income	340	1,195	755	49
Net income	62	589	345	(73)
Income available for common stock	58	583	339	(79)
2002 ⁽¹⁾				
PG&E CORPORATION				
Operating revenues ⁽¹⁾	\$ 2,397	\$2,947	\$2,712	\$2,449
Operating income ⁽¹⁾⁽³⁾	542	1,069	1,071	1,272
Income from continuing operations ⁽¹⁾⁽³⁾	191	479	456	597
Net income (loss) ⁽³⁾⁽⁵⁾	(2,189)	466	218	631
Earnings per common share from continuing operations, basic	0.50	1.28	1.25	1.64
Earnings per common share from continuing operations, diluted	0.48	1.22	1.23	1.62
Common stock price per share:				
High	14.18	17.75	23.75	23.66
Low	8.17	8.00	16.35	18.86
UTILITY				
Operating revenues	\$ 2,398	\$2,949	\$2,714	\$2,453
Operating income ⁽³⁾	547	1,059	1,059	1,248
Net income ⁽³⁾	227	527	469	596
Income available for common stock	221	520	463	590

- (1) The operating results of NEGT have been excluded from continuing operations and reported as discontinued operations for all periods. (See Note 5 of the Notes to the Consolidated Financial Statements). Operating revenues, operating income (loss) and income (loss) from continuing operations previously reported for quarter ended March 31, 2003 were \$2,401 million, \$(129) million and \$(278) million; \$2,926 million, \$703 million and \$219 million for the quarter ended June 30, 2003; and \$3,103 million, \$1,173 million and \$508 million for the quarter ended September 30, 2003. Operating revenues, operating income (loss) and income (loss) from continuing operations previously reported for the quarters ended March 31, 2002 were \$2,935 million, \$1,301 million and \$623 million; \$2,937 million, \$783 million and \$279 million for the quarter ended June 30, 2002; \$2,947 million, \$1,069 million and \$479 million for the quarter ended September 30, 2002; and \$2,968 million, \$(1,949) million and \$(1,417) million for the quarter ended December 31, 2002.
- (2) Operating revenues for the quarter ended December 31, 2003, include the recognition of a regulatory liability of approximately \$125 million for surcharge revenues collected during 2003.
- (3) Operating income, income from continuing operations, and net income for the quarter ended March 31, 2002 includes a \$970 million non-cash reduction to the costs of electricity related to a reversal of ISO charges.
- (4) Net loss for the quarter ended March 31, 2003 includes \$200 million of impairments, write-offs and charges recognized by NEGT.

These impairments have been excluded from continuing operations and are reported as discontinued operations.

- (5) Net income for the quarter ended December 31, 2002 includes \$2.4 billion of impairments, write-offs and charges recognized by NEGТ. These impairments have been excluded from continuing operations and are reported as discontinued operations.

INDEPENDENT AUDITORS' REPORT

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 (a Debtor-in-Possession) and subsidiaries (the "Utility") as of December 31, 2003 and 2002, and the related consolidated statements of operations, cash flows and shareholders' equity of the Company and the related consolidated statements of operations, cash flows and shareholders' equity of the Utility for each of the three years in the period ended December 31, 2003. 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 auditing standards generally accepted in the United States of America. 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, 2003 and 2002, and the respective results of their consolidated operations and cash flows for each of the three years in the period ended December 31, 2003, 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, 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. Additionally, as described in Note 5 to the Notes to the Consolidated Financial Statements, during 2003, the Company changed the method of reporting hedge transactions. During 2002, the Company adopted new accounting standards to account for goodwill and intangible assets, impairment of long-lived assets, discontinued operations, gains and losses on debt extinguishment and certain derivative contracts. During 2001, the Company and the Utility adopted new accounting standards related to derivatives and certain interpretations of the Derivatives Implementation Group of the Financial Accounting Standards Board.

As discussed in Note 5 of the Notes to the Consolidated Financial Statements, revenues and expenses of discontinued operations for the years ended December 31, 2002 and 2001 have been revised.

The accompanying consolidated financial statements have been prepared on a going concern basis of accounting. As discussed in Notes 1 and 2 of the Notes to the Consolidated Financial Statements, the Utility, a subsidiary of the Company, has incurred power purchase costs substantially in excess of amounts charged to customers in rates. On April 6, 2001, the Utility sought protection from its creditors by filing a voluntary petition under provisions of Chapter 11 of the U.S. Bankruptcy Code. These matters raise substantial doubt about the ability of the Company and of the Utility to continue as going concerns. Managements' plans in regard to these matters are also described in Note 2 of the Notes to the Consolidated Financial Statements. The respective consolidated financial statements do not include any adjustments that might result from the outcome of these uncertainties.

DELOITTE & TOUCHE LLP
San Francisco, California
February 18, 2004

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 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 21

PG&E CORPORATION AND PACIFIC GAS AND ELECTRIC COMPANY SUBSIDIARIES

SUBSIDIARY OR AFFILIATE NAME	JURISDICTION OF FORMATION
1989 Oakland Housing Partnership Associates, L.P.	CA
1992 Oakland Regional Housing Partnership Associates, a California Limited Partnership	CA
1994 Oakland Regional Housing Partnership Associates, a California Limited Partnership	CA
201 Turk Street, L.P.	CA
Alaska Gas Exploration Associates	CA
Alhambra Pacific Joint Venture	CA
Altresco, Inc.	CO
Aplomado Power Corporation	CA
Athens Generating Company, L.P.	DE
Attala Generating Company, LLC	DE
Attala Power Corporation	DE
Badger Generating Company, LLC	DE
Badger Power Corporation	DE
Balch 1 and 2 Project LLC	CA
Barakat & Chamberlin, Inc.	CA
Battle Creek Project LLC	CA
Beale Generating Company	DE
Beech Power Corporation	DE
Berkshire Feedline Acquisition Limited Partnership	MA
Berkshire Pittsfield, Inc.	CO
Black Hawk III Power Corporation	CA
Black Hawk Power Corporation	CA

Bluebonnet Generating Company, LLC	DE
Bluebonnet Power Corporation	DE
BPS I, Inc.	CA
Buckeye Power Corporation	DE
Bucks Creek Project LLC	CA
Calaska Energy Company	CA
Carneys Point Generating Company	DE
Cedar Bay Cogeneration, Inc.	DE
Cedar Bay Generating Company, Limited Partnership	DE
Chambers Cogeneration, Limited Partnership	DE
Chico Commons, a California Limited Partnership	CA
Chili Bar Project LLC	CA
Citrus Generating Company, L.P.	DE
Clearfield Properties, Inc.	DE
Colstrip Energy, Limited Partnership	MT
Conaway Conservancy Group Joint Venture	Yolo County, CA
Conaway Ranch Company, The	CA
Cooper's Hawk Power Corporation	CA
Covert Generating Company, LLC	DE
Covert Power Corporation	DE
Crane Valley Project LLC	CA
DeSabra-Centerville Project LLC	CA
Diablo Canyon LLC	CA

SUBSIDIARY OR AFFILIATE NAME	JURISDICTION OF FORMATION
Dispersed Gen Properties, LLC	DE
Dispersed Generating Company, LLC	DE
Dispersed Power Corporation	DE
DPR, Inc.	CA
Drum-Spaulding Project LLC	CA
Eagle Power Corporation	CA
Electric Generation LLC	CA
Elm Power Corporation	DE
Energy Services Ventures, Inc.	DE
ETrans LLC	CA
Eucalyptus Power Corporation	DE
Eureka Energy Company	CA
Falcon Power Corporation	CA
Fellows Generating Company, L.P.	DE
First Arizona Land Corporation	DE
First California Land Corporation	DE
First Massachusetts Land Company, LLC	DE
First Oregon Land Corporation	DE
Fuelco LLC	DE
Gannet Power Corporation	CA
Garnet Power Corporation	DE
Gas Transmission Corporation	CA
Gas Transmission Holdings Corporation	CA
Gas Transmission Northwest Corporation	CA
Gas Transmission Service Company, LLC	DE
Gator Generating Company, L.P.	DE
GenHoldings I, LLC	DE
Gilia Enterprises	CA
Goose Lake Generating Company, LLC	DE
Goose Lake Power Corporation	DE
Granite Generating Company, L.P.	DE
Granite Water Supply Company, Inc.	DE
Gray Hawk Power Corporation	DE
GTN Holdings LLC	DE
GTrans LLC	CA
Haas-Kings River Project LLC	CA
Hamilton Branch Project LLC	CA
Harlan Power Corporation	CA
Harquahala Generating Company, LLC	DE
Harquahala Power Corporation	DE
Hat Creek 1 and 2 Project LLC	CA
Helms Project LLC	CA
Hermiston Generating Company, L.P.	DE
Heron Power Corporation	CA
Indian Orchard Generating Company, Inc.	DE
Indiantown Cogeneration Funding Corporation	DE
Indiantown Cogeneration, L.P.	DE
Indiantown Project Investment Partnership, L.P.	DE

SUBSIDIARY OR AFFILIATE NAME	JURISDICTION OF FORMATION
Iroquois Gas Transmission System, L.P.	DE
Iroquois Pipeline Investment, LLC	DE
J. Makowski Associates, Inc.	MA
J. Makowski Pittsfield, Inc.	DE
J. Makowski Services, Inc.	DE
Jaeger Power Corporation	CA
JMC Altresco, Inc.	CO
JMC Iroquois, Inc.	DE
JMC Selkirk Holdings, Inc.	DE
JMC Selkirk, Inc.	DE
JMCS I Holdings, Inc.	DE
JMCS I Management, Inc.	DE
Juniper Power Corporation	DE
Kentucky Hydro Holdings, LLC	DE
Kerckhoff 1 and 2 Project LLC	CA
Kern Canyon Project LLC	CA
Keystone Cogeneration Company, L.P.	DE
Keystone Urban Renewal Limited Partnership	DE
Kilarc-Cow Creek Project LLC	CA
La Paloma Generating Company, LLC	DE
La Paloma Power Corporation	DE
Lake Road Generating Company, L.P.	DE
Lake Road Power I, LLC	DE
Lake Road Power II, LLC	DE
Larkspur Power Corporation	DE
Leechburg Properties, Inc.	DE
Liberty Generating Company, LLC	DE
Liberty Generating Corporation	DE
Liberty Urban Renewal, LLC	DE
Logan Generating Company, L.P.	DE
Long Creek Generating Company, LLC	DE
Long Creek Power Corporation	DE
Loon Power Corporation	DE
Madison Wind Power Corporation	DE
Madison Windpower LLC	DE
Magnolia Power Corporation	DE
Mantua Creek Generating Company, L.P.	DE
Mantua Creek Urban Renewal, L.P.	DE
Marengo Ranch Joint Venture	Sacramento County, CA
Mason Generating Company	DE
MASSPOWER	MA
MASSPOWER, L.L.C.	DE
McCloud-Pit Project LLC	CA
McSweeney Ranch Joint Venture	Yolo County, CA
Meadow Valley Generating Company, LLC	DE
Meadow Valley Power Corporation	DE
Merced Falls Project LLC	CA

SUBSIDIARY OR AFFILIATE NAME	JURISDICTION OF FORMATION
Merlin Power Corporation	CA
Merritt Community Capital Fund V, L.P.	CA
MidColumbia Generating Company, LLC	DE
MidColumbia Power Corporation	DE
Millennium Power Partners, L.P.	DE
Miocene Project LLC	CA
Mokelumne River Project LLC	CA
Morro Bay Mutual Water Company	CA
Morrow Generating Company, LLC	DE
Morrow Power Corporation	DE
Moss Landing Mutual Water Company	CA
Narrows Project LLC	CA
National Energy & Gas Transmission, Inc.	DE
National Energy Construction Company, LLC	DE
National Energy Generating Company, LLC	DE
National Energy Generating Holdings, Inc.	DE
National Energy Generating Services, LLC	DE
National Energy Holdings Corporation	CA
National Energy Power Company, LLC	DE
Natural Gas Corporation of California	CA
NEGT Acquisition Company, LLC	DE
NEGT Construction Agency Services I, LLC	DE
NEGT Construction Agency Services II, LLC	DE
NEGT Construction Finance Company, LLC	DE
NEGT Energy Company, LLC	DE
NEGT Energy Trading - Gas Corporation	CA
NEGT Energy Trading Holdings Corporation	CA
NEGT Energy Trading Holdings, LLC	DE
NEGT Energy Trading Power - L.P.	DE
NEGT Enterprises, Inc.	CA
NEGT ET Investments Corporation	DE
NEGT ET Synfuel #2, LLC	DE
NEGT ET Synfuel 166, LLC	DE
NEGT Generating New England, Inc.	DE
NEGT Generating New England, LLC	DE
NEGT International Development Holdings, LLC	DE
NEGT International, Inc.	CA
NEGT Management Services Company	CA
NEGT Overseas, Inc.	CA
NEGT Services Company, LLC	DE
New Athens Generating Company, LLC	DE
New Covert Generating Company, LLC	DE
New Harquahala Generating Company, LLC	DE
New Millennium Generating Company, LLC	DE
Newco Energy Corporation	CA
NGC Production Company	CA
North Baja Pipeline, LLC	DE
Northampton Fuel Supply Company, Inc.	DE

SUBSIDIARY OR AFFILIATE NAME	JURISDICTION OF FORMATION
Northampton Generating Company, L.P.	DE
Northampton Water Supply, Inc.	DE
Oat Creek Associates Joint Venture	Yolo County, CA
Okeechobee Generating Company, LLC	DE
Okeechobee Power Corporation	DE
Okeelanta Power Limited Partnership	DE
Orchard Gas Corporation	DE
Osprey Power Corporation	CA
Otay Mesa Power Corporation	DE
Pacific California Gas System, Inc.	CA
Pacific Conservation Services Company	CA
Pacific Energy Fuels Company	CA
Pacific Gas and Electric Company	CA
Pacific Gas and Electric Housing Fund Partnership, L.P.	CA
Pacific Gas Properties Company	CA
Pacific Gas Transmission Company	CA
Pacific Gas Transmission International, Inc.	CA
Pacific Properties	CA
Pacific Venture Capital, LLC	DE
Parkhill Energy Management Ltd.	Alberta, Canada
Peach I Power Corporation	DE
Peach IV Power Corporation	DE
Peak Power Generating Company, Inc.	CA
Pelican Power Corporation	CA
PentaGen Investors, L.P.	DE
Peregrine Power Corporation	CA
PG&E CalHydro, LLC	CA
PG&E Capital II	DE
PG&E Capital III	DE
PG&E Capital IV	DE
PG&E Capital, LLC	DE
PG&E Corporation	CA
PG&E Corporation Australia Pty Ltd. (in process of liquidation)	Australia
PG&E Corporation Australian Holdings Pty Ltd. (in process of liquidation)	Australia
PG&E Corporation Support Services, Inc.	DE
PG&E Energy Trading Australia Pty Ltd. (in process of liquidation)	Australia
PG&E Funding LLC	DE
PG&E Holdings, LLC	DE
PG&E National Energy Group, LLC	DE
PG&E Operating Services Company	CA
PG&E Overseas Holdings I, Ltd.	Cayman Islands
PG&E Overseas Holdings II, Ltd.	Cayman Islands
PG&E Strategic Capital, Inc.	DE
PG&E Telecom Holdings, LLC	DE
PG&E Telecom, LLC	DE

SUBSIDIARY OR AFFILIATE NAME	JURISDICTION OF FORMATION
PG&E Ventures ePro, LLC	DE
PG&E Ventures, LLC	DE
Phoenix Project LLC	CA
Pit 1 Project LLC	CA
Pit 3, 4 and 5 Project LLC	CA
Pittsfield Generating Company, L.P.	DE
Pittsfield Partners, Inc.	CO
Plains End, LLC	DE
Plover Power Corporation	CA
Poe Project LLC	CA
Potter Valley Project LLC	CA
Power Services Company	CA
Properties Holdings, LLC	DE
PTP Services, LLC	DE
PTTP Services LLC	CA
Quantum Ventures	CA
Raptor Holdings Company	CA
Rock Creek-Cresta Project LLC	CA
Rocksavage Services I, Inc.	DE
San Gorgonio Power Corporation	DE
Schoolhouse Lane Apartments L.P.	CA
Scrubgrass Generating Company, L.P.	DE
Scrubgrass Power Corp.	PA
Selkirk Cogen Funding Corporation	DE
Selkirk Cogen Partners, L.P.	DE
Spencer Station Generating Company, L.P.	DE
Spencer Station Power Corporation	DE
Spring-Gap Stanislaus Project LLC	CA
Spruce Limited Partnership	DE
Spruce Power Corporation	DE
Standard Pacific Gas Line Incorporated	CA
Stanfield Hub Services, LLC	WA
TES LLC	CA
Topaz Power Corporation	DE
Toyon Enterprises	CA
Tule River Project LLC	CA
U.S. Operating Services Holdings, Inc.	CA
Umatilla Generating Company, L.P.	DE
Upper NF Feather River Project LLC	CA
USG Services Company, LLC	DE
USGen Holdings, Inc.	DE
USGen New England, Inc.	DE
USGen Services Company, LLC	DE
USOSC Holdings, Inc.	DE
Valley Real Estate, Inc.	CA
Virtual Credit Services, LLC	DE
White Pine Generating Company, LLC	DE

EXHIBIT 23

INDEPENDENT AUDITORS' CONSENT

We consent to the incorporation by reference in Registration Statements No. 333-16255 and 333-25685 on Form S-3 and 333-16253, 333-27015, 333-68155, 333-46772, 333-77145, 333-77149 and 333-73054 on Form S-8 of PG&E Corporation and Registration Statements No. 33-64136, 33-50707, 33-62488, 33-61959 and 333-10994 on Form S-3 of Pacific Gas and Electric Company of our reports dated February 18, 2004 (which express an unqualified opinion and include explanatory paragraphs relating to accounting changes, a revision to the 2002 and 2001 financial statements of PG&E Corporation and going concern uncertainties), 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, 2003.

DELOITTE & TOUCHE LLP

San Francisco, California
February 18, 2004

EXHIBIT 24.1

**RESOLUTION OF THE
BOARD OF DIRECTORS OF
PG&E CORPORATION**

February 18, 2004

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, 2003, 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, 2003, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of 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 Chairman of the Board, Chief Executive Officer, and President, the Senior Vice President and Chief Financial Officer, and the Senior Vice President and Controller of this corporation the Form 10-K Annual Report for the year ended December 31, 2003, 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 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 18, 2004; 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 19th day of February, 2004.

LINDA Y.H. CHENG

Linda Y.H. Cheng 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 18, 2004

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, 2003, 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, 2003, to be filed with the Securities and Exchange Commission;

BE IT RESOLVED that each of 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, 2003, 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 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 18, 2004; 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 19th day of February, 2004.

LINDA Y.H. CHENG

Linda Y.H. Cheng Corporate Secretary
PACIFIC GAS AND ELECTRIC COMPANY

C O R P O R A T E

S E A L

EXHIBIT 24.2

POWER OF ATTORNEY

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints 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, 2003, 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 18th day of February, 2004.

LESLIE S. BILLER

Leslie S. Biller

DAVID A. COULTER

David A. Coulter

C. LEE COX

C. Lee Cox

WILLIAM S. DAVILA

William S. Davila

ROBERT D. GLYNN, JR.

Robert D. Glynn, Jr.

DAVID M. LAWRENCE, MD

David M. Lawrence, MD

MARY S. METZ

Mary S. Metz

CARL E. REICHARDT

Carl E. Reichardt

BARRY LAWSON WILLIAMS

Barry Lawson Williams

POWER OF ATTORNEY

ROBERT D. GLYNN, JR., the undersigned, Chairman of the Board, Chief Executive Officer, and President of PG&E Corporation, hereby constitutes and appoints 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 Chairman of the Board, Chief Executive Officer, and President (principal executive officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2003, 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 18th day of February, 2004.

ROBERT D. GLYNN, JR.
Robert D. Glynn, Jr.

POWER OF ATTORNEY

PETER A. DARBEE, the undersigned, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby constitutes and appoints 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 and Chief Financial Officer (principal financial officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2003, 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 18th day of February, 2004.

PETER A. DARBEE
Peter A. Darbee

POWER OF ATTORNEY

CHRISTOPHER P. JOHNS, the undersigned, Senior Vice President and Controller of PG&E Corporation, hereby constitutes and appoints 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 and Controller (principal accounting officer) of said corporation the Form 10-K Annual Report for the year ended December 31, 2003, 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 18th day of February, 2004.

CHRISTOPHER P. JOHNS
Christopher P. Johns

POWER OF ATTORNEY

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints 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, 2003, 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 18th day of February, 2004.

LESLIE S. BILLER

Leslie S. Biller

DAVID A. COULTER

David A. Coulter

C. LEE COX

C. Lee Cox

WILLIAM S. DAVILA

William S. Davila

ROBERT D. GLYNN, JR.

Robert D. Glynn, Jr.

DAVID M. LAWRENCE, MD

David M. Lawrence, MD

MARY S. METZ

Mary S. Metz

CARL E. REICHARDT

Carl E. Reichardt

GORDON R. SMITH

Gordon R. Smith

BARRY LAWSON WILLIAMS

Barry Lawson Williams

POWER OF ATTORNEY

GORDON R. SMITH, the undersigned, President and Chief Executive Officer of Pacific Gas and Electric Company, hereby constitutes and appoints 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, 2003, 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 18th day of February, 2004.

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 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, 2003, 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 18th day of February, 2004.

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 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, 2003, 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 18th day of February, 2004.

DINYAR B. MISTRY
Dinyar B. Mistry

EXHIBIT 31.1

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)**

I, Robert D. Glynn, Jr., certify that:

1. I have reviewed this annual report on Form 10-K for the year ended December 31, 2003 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)) 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. 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
 - c. 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 the 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 19, 2004

ROBERT D. GLYNN, JR.

Robert D. Glynn, Jr.

Chairman, Chief Executive Officer and President
PG&E Corporation

EXHIBIT 31.1

**CERTIFICATION OF PRINCIPAL FINANCIAL 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, 2003 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)) 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. 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
 - c. 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 the 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 19, 2004

PETER A. DARBEE

Peter A. Darbee Senior Vice President and Chief Financial Officer PG&E Corporation

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, 2003 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)) 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. 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
 - c. 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 the 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 19, 2004

GORDON R. SMITH

Gordon R. Smith President and Chief Executive Officer Pacific Gas and Electric Company

EXHIBIT 31.2

**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, 2003 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)) 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. 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
 - c. 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 the 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 19, 2004

KENT M. HARVEY

Kent M. Harvey Senior Vice President - Chief Financial Officer and Treasurer Pacific Gas and Electric Company

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, 2003, I, Robert D. Glynn, Jr., Chairman, Chief Executive Officer and President 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, 2003, 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, 2003, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

ROBERT D. GLYNN, JR.
ROBERT D. GLYNN, JR.

Chairman, Chief Executive Officer and President

February 19, 2004

**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, 2003, I, Peter A. Darbee, Senior Vice President and Chief Financial 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, 2003, 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, 2003, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

PETER A. DARBEE
PETER A. DARBEE

Senior Vice President and Chief Financial Officer

February 19, 2004

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, 2003, 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, 2003, 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, 2003, 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 19, 2004

**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, 2003, 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, 2003, 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, 2003, 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 19, 2004

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