

PG&E CORP

FORM 10-Q (Quarterly Report)

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UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C., 20549
FORM 10-Q

(Mark One)

☒ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (D) OF THE
SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended March 31, 2004

OR

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

For the transition period from _____ to _____

Commission File Number	Exact Name of Registrant as specified in its charter	State or other Jurisdiction 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 94177

PG&E Corporation
One Market, Spear Tower
Suite 2400
San Francisco, California 94105

Address of principal executive offices, including zip code

Pacific Gas and Electric Company
(415) 973-7000

PG&E Corporation
(415) 267-7000

Registrant's telephone number, including area code

Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding twelve months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.

Yes ☒

No ☐

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

Yes ☒

No ☐

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of latest practicable date.

Common Stock Outstanding, April 28, 2004:

PG&E Corporation

398,752,930 shares (excluding 23,815,500 shares held by a wholly owned subsidiary)

Pacific Gas and Electric Company

Wholly owned by PG&E Corporation

**PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY,**

FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2004
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PART I. FINANCIAL INFORMATION
ITEM 1: CONSOLIDATED FINANCIAL STATEMENTS

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions, except per share amounts)

	(Unaudited)	
	Three Months Ended	
	March 31,	
	2004	2003
Operating Revenues		
Electric	\$ 1,791	\$ 1,305
Natural gas	931	828
Total operating revenues	2,722	2,133
Operating Expenses		
Cost of electricity	561	544
Cost of natural gas	578	471
Operating and maintenance	816	711
Recognition of regulatory assets	(4,900)	-
Depreciation, amortization and decommissioning	312	310
Reorganization professional fees and expenses	2	35
Total operating (gain) expenses	(2,631)	2,071
Operating Income	5,353	62
Reorganization interest income	8	10
Interest income	6	2
Interest expense	(231)	(255)
Other expense, net	(27)	8
Income (Loss) Before Income Taxes	5,109	(173)
Income tax provision (benefit)	2,076	(90)
Income (Loss) From Continuing Operations	3,033	(83)
Discontinued Operations		
Loss from operations of NEGT (net of income tax benefit of \$156 million for the three months ended March 31, 2003)	-	(265)
Net Income (Loss) Before Cumulative Effect of Changes in Accounting Principles	3,033	(348)
Cumulative effect of changes in accounting principles of \$(5) million in 2003 related to discontinued operations (net of income tax benefit of \$3 million) and \$(1) million related to continuing operations (net of income tax benefit of \$1 million)	-	(6)
Net Income (Loss)	\$ 3,033	\$ (354)
Weighted Average Common Shares Outstanding, Basic	393	382
Earnings (Loss) Per Common Share from Continuing Operations, Basic	\$ 7.36	\$ (0.22)
Net Earnings (Loss) Per Common Share, Basic	\$ 7.36	\$ (0.93)
Earnings (Loss) Per Common Share from Continuing Operations, Diluted	\$ 7.21	\$ (0.22)
Net Earnings (Loss) Per Common Share, Diluted	\$ 7.21	\$ (0.93)

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)

	Balance At	
	March 31,	December 31,
	2004	2003
	(Unaudited)	
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 3,460	\$ 3,658

Restricted cash	531	403
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$61 million in 2004 and \$68 million in 2003)	2,068	2,424
Related parties	-	15
Regulatory balancing accounts	546	248
Inventories:		
Gas stored underground	80	166
Materials and supplies	130	126
Prepaid expenses and other	54	171
Total current assets	6,869	7,211
Property, Plant and Equipment		
Electric	20,665	20,468
Gas	8,431	8,355
Construction work in progress	417	379
Other	19	20
Total property, plant and equipment	29,532	29,222
Accumulated depreciation	(11,236)	(11,115)
Net property, plant and equipment	18,296	18,107
Other Noncurrent Assets		
Restricted cash	7,278	361
Regulatory assets	6,993	2,001
Nuclear decommissioning funds	1,547	1,478
Other	1,156	1,017
Total other noncurrent assets	16,974	4,857
TOTAL ASSETS	\$ 42,139	\$ 30,175

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	Balance At	
	March 31,	December 31,
	2004 (Unaudited)	2003
LIABILITIES AND SHAREHOLDERS' EQUITY		
Liabilities Not Subject to Compromise		
Current Liabilities		
Long-term debt, classified as current	\$ 4	\$ 310
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	428	657
Regulatory balancing accounts	431	186
Other	547	402
Interest payable	223	174
Income taxes payable	417	256
Other	956	867
Total current liabilities	3,296	3,142
Noncurrent Liabilities		
Long-term debt	10,000	3,314
Rate reduction bonds	796	870
Regulatory liabilities	4,249	3,979
Asset retirement obligations	1,236	1,218
Deferred income taxes	2,804	856
Deferred tax credits	125	127
Net investment in NEG-T	1,219	1,216
Preferred stock of subsidiary with mandatory redemption provisions	137	137

Other	1,636	1,497
Total noncurrent liabilities	22,202	13,214
Liabilities Subject to Compromise		
Financing debt	5,603	5,603
Trade creditors	3,439	3,715
Total liabilities subject to compromise	9,042	9,318
Commitments and Contingencies (Notes 1, 2, 3, and 6)	-	-
Preferred Stock of Subsidiaries	286	286
Preferred Stock		
Preferred stock, no par value, 80,000,000 shares, \$100 par value, 5,000,000 shares, none issued	-	-
Common Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 420,671,789 common and 1,631,638 restricted shares in 2004 and 408,610,591 common and 1,569,260 restricted shares in 2003	6,540	6,468
Common stock held by subsidiary, at cost, 23,815,500 shares	(690)	(690)
Unearned compensation	(31)	(20)
Accumulated earnings (deficit)	1,575	(1,458)
Accumulated other comprehensive loss	(81)	(85)
Total common shareholders' equity	7,313	4,215
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 42,139	\$ 30,175

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited) Three Months Ended March 31,	
	2004	2003
Cash Flows From Operating Activities		
Net income (loss)	\$ 3,033	\$ (354)
Loss from discontinued operations	-	265
Cumulative effect of changes in accounting principles	-	6
Net income from continuing operations	3,033	(83)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation, amortization and decommissioning	312	310
Recognition of regulatory assets	(4,900)	-
Deferred income taxes and tax credits, net	1,926	(15)
Other deferred charges and noncurrent liabilities	237	189
Gain on sale of assets	(16)	-
Net effect of changes in operating assets and liabilities:		
Restricted cash	(128)	206
Accounts receivable	352	402
Inventories	82	71
Accounts payable	(257)	81
Accrued taxes	65	(128)
Regulatory balancing accounts, net	(53)	(51)
Other working capital	287	4
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(20)	(39)
Other, net	(33)	(14)
Net cash provided by operating activities	887	933

Cash Flows From Investing Activities		
Capital expenditures	(342)	(371)
Net proceeds from sale of assets	18	5
Increase in restricted cash	(6,917)	-
Other, net	(65)	9
Net cash used by investing activities	(7,306)	(357)
Cash Flows From Financing Activities		
Net proceeds from long-term debt issued	6,547	-
Long-term debt matured, redeemed or repurchased	(310)	-
Rate reduction bonds matured	(74)	(74)
Common stock issued	58	21
Net cash provided (used) by financing activities	6,221	(53)
Net change in cash and cash equivalents	(198)	523
Cash and cash equivalents at January 1	3,658	3,532
Cash and cash equivalents at March 31	\$ 3,460	\$ 4,055

Supplemental disclosures of cash flow information

Cash received for:		
Reorganization interest income	\$ 8	\$ 11
Cash paid for:		
Interest (net of amounts capitalized)	197	149
Income taxes paid, net	-	1
Reorganization professional fees and expenses	5	22
Supplemental disclosures of noncash investing and financing activities		
Transfer of liabilities and other payables subject to compromise from operating assets and liabilities	(257)	47

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

	(Unaudited)	
	Three Months Ended	
	March 31,	
(in millions)	2004	2003
Operating Revenues		
Electric	\$ 1,791	\$ 1,305
Natural gas	931	830
Total operating revenues	2,722	2,135
Operating Expenses		
Cost of electricity	561	554
Cost of natural gas	578	486
Operating and maintenance	808	712
Recognition of regulatory assets	(4,900)	-
Depreciation, amortization and decommissioning	311	310
Reorganization professional fees and expenses	2	35
Total operating (gain) expenses	(2,640)	2,097
Operating Income	5,362	38
Reorganization interest income	8	10
Interest income	3	1
Interest expense (non-contractual interest expense of \$31 million in 2004 and \$30 million in 2003)	(213)	(220)
Other income, net	13	15
Income (Loss) Before Income Taxes	5,173	(156)

Income tax provision (benefit)	2,099	(84)
Income (Loss) Before Cumulative Effect of a Change in Accounting Principle	3,074	(72)
Cumulative effect of change in accounting principle (net of income tax benefit of \$1 million for the three months ended March 31, 2003)	-	(1)
Net Income (Loss)	3,074	(73)
Preferred dividend requirement	8	6
Income (Loss) Available for (Allocated to) Common Stock	\$ 3,066	\$ (79)

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	Balance At	
	March 31, 2004 (Unaudited)	December 31, 2003
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 2,845	\$ 2,979
Restricted cash	529	403
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$61 million in 2004 and \$68 million in 2003)	2,068	2,424
Related parties	2	17
Regulatory balancing accounts	546	248
Inventories:		
Gas stored underground	80	166
Materials and supplies	130	126
Prepaid expenses and other	52	100
Total current assets	6,252	6,463
Property, Plant and Equipment		
Electric	20,665	20,468
Gas	8,431	8,355
Construction work in progress	417	379
Total property, plant and equipment	29,513	29,202
Accumulated depreciation	(11,221)	(11,100)
Net property, plant and equipment	18,292	18,102
Other Noncurrent Assets		
Restricted cash	6,917	-
Regulatory assets	6,993	2,001
Nuclear decommissioning funds	1,547	1,478
Other	1,098	1,051
Total other noncurrent assets	16,555	4,530
TOTAL ASSETS	\$ 41,099	\$ 29,095

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	Balance At	
	March 31, 2004 (Unaudited)	December 31, 2003

LIABILITIES AND SHAREHOLDERS' EQUITY**Liabilities Not Subject to Compromise****Current Liabilities**

Long-term debt, classified as current	\$ 4	\$ 310
Current portion of rate reduction bonds	290	290
Accounts payable:		
Trade creditors	427	657
Related parties	93	224
Regulatory balancing accounts	431	186
Other	530	365
Interest payable	208	153
Income taxes payable	148	-
Deferred income taxes	66	86
Other	840	673
Total current liabilities	3,037	2,944

Noncurrent Liabilities

Long-term debt	9,117	2,431
Rate reduction bonds	796	870
Regulatory liabilities	4,249	3,979
Asset retirement obligations	1,236	1,218
Deferred income taxes	3,370	1,334
Deferred tax credits	125	127
Preferred stock with mandatory redemption provisions	137	137
Other	1,573	1,464
Total noncurrent liabilities	20,603	11,560

Liabilities Subject to Compromise

Financing debt	5,603	5,603
Trade creditors	3,622	3,899
Total liabilities subject to compromise	9,225	9,502

Commitments and Contingencies (Notes 1, 2, 3 and 6)

-	-
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Shareholders' Equity

Preferred stock without mandatory redemption provisions		
Nonredeemable, 5% to 6%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 7.04%, outstanding 5,973,456 shares	149	149
Common stock, \$5 par value, authorized 800,000,000 shares, issued 321,314,760 shares	1,606	1,606
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	2,040	1,964
Reinvested earnings	4,772	1,706
Accumulated other comprehensive loss	(3)	(6)
Total shareholders' equity	8,234	5,089

TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 41,099	\$ 29,095
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See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY, A DEBTOR-IN-POSSESSION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Three Months Ended	
	March 31,	
	2004	2003
Cash Flows From Operating Activities		
Net income (loss)	\$ 3,074	\$ (73)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		

Depreciation, amortization and decommissioning	311	310
Recognition of regulatory assets	(4,900)	-
Deferred income taxes and tax credits, net	2,014	117
Other deferred charges and noncurrent liabilities	279	80
Gain on sale of assets	(16)	-
Cumulative effect of a change in accounting principle	-	1
Net effect of changes in operating assets and liabilities:		
Restricted cash	(126)	(41)
Accounts receivable	353	381
Inventories	82	71
Accounts payable	(256)	122
Accrued taxes	98	(176)
Regulatory balancing accounts, net	(53)	(51)
Other working capital	253	24
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(20)	(39)
Other, net	(84)	8
Net cash provided by operating activities	1,009	734
Cash Flows From Investing Activities		
Capital expenditures	(342)	(371)
Net proceeds from sale of assets	18	5
Increase in restricted cash	(6,917)	-
Other, net	(65)	9
Net cash used by investing activities	(7,306)	(357)
Cash Flows From Financing Activities		
Net proceeds from issuance of long-term debt	6,547	-
Long-term debt matured, redeemed or repurchased	(310)	-
Rate reduction bonds matured	(74)	(74)
Net cash provided (used) by financing activities	6,163	(74)
Net change in cash and cash equivalents	(134)	303
Cash and cash equivalents at January 1	2,979	3,343
Cash and cash equivalents at March 31	\$ 2,845	\$ 3,646
Supplemental disclosures of cash flow information		
Cash received for:		
Reorganization interest income	\$ 8	\$ 11
Cash paid for:		
Interest (net of amounts capitalized)	175	116
Reorganization professional fees and expenses	5	22
Supplemental disclosures of noncash investing and financing activities		
Transfer of liabilities and other payables subject to compromise (to) from operating assets and liabilities, net	(257)	47

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED 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. Both PG&E Corporation and the Utility are headquartered in San Francisco, California.

As discussed further in Note 2, on April 12, 2004, the Utility's plan of reorganization, or Plan of Reorganization, under the provisions of Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, became effective. During its Chapter 11 proceeding, the Utility retained control of its assets and was authorized to operate its business as a debtor-in-possession.

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 Condensed Consolidated Financial Statements will refer to NEGT. NEGT's 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. On May 3, 2004, NEGT's plan of reorganization, which eliminates PG&E Corporation's equity ownership, was confirmed by the bankruptcy court. 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 Condensed Consolidated Balance Sheet of PG&E Corporation at March 31, 2004. 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 periods, are reflected as discontinued operations in the Consolidated Financial Statements (see Note 4 for further information).

This Quarterly Report on Form 10-Q is a combined report of PG&E Corporation and the Utility. Therefore, the Notes to the unaudited Consolidated Financial Statements apply to both PG&E Corporation and the Utility. PG&E Corporation's Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's Condensed Consolidated Financial Statements include its accounts and those of its wholly owned and controlled subsidiaries, and variable interest entities for which it is subject to a majority of the risk of loss or gain. Both PG&E Corporation's and the Utility's Consolidated Balance Sheets at December 31, 2003 were derived from the audited Consolidated Balance Sheets included in the combined 2003 Annual Report filed with the Current Report on Form 8-K dated March 2, 2004.

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.

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 were subject to uncertainty while the Utility was in Chapter 11. 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 Condensed Consolidated Statements of Operations.

Adoption of New Accounting Policies and Summary of Significant Accounting Policies

The accounting policies used by PG&E Corporation and the Utility include those necessary for rate-regulated enterprises, which reflect the ratemaking policies of the California Public Utilities Commission, or the CPUC, and the Federal Energy Regulatory Commission, or the FERC. Except as disclosed below, PG&E Corporation and the Utility are following the same accounting policies discussed in their combined 2003 Annual Report filed with the Current Report on Form 8-K dated March 2, 2004.

Participating Securities and the Two-Class Method

On March 31, 2004, the Financial Accounting Standards Board, or FASB, ratified the consensus reached by its Emerging Issues Task Force, or EITF, on EITF Issue 03-06, "Participating Securities and the Two-Class Method under FASB Statement No. 128," or EITF 03-06. EITF 03-06 provides additional guidance related to the calculation of earnings per share under FASB Statement No. 128, "Earnings per Share," or SFAS No. 128, which includes application of the "two-class" method in computing earnings per share, identification of participating securities, and requirements for the allocation of undistributed earnings (and losses) to participating securities. PG&E Corporation adopted EITF 03-06 for the quarter ending March 31, 2004 and all prior periods presented.

PG&E Corporation currently has outstanding \$280 million in convertible subordinated 9.50% notes due 2010, or Convertible Notes, that are entitled to receive (non-cumulative) dividend payments without exercising the conversion option. These Convertible Notes meet the criteria of a participating security in the calculation of basic earnings per share using the "two-class" method of SFAS No. 128. Therefore, EITF 03-6 requires that earnings be allocated between common stock and the participating security.

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. FIN 46R provides that an entity is a variable interest entity if it does not have sufficient equity investment at risk, or if the holders of the entity's equity instruments lack the essential characteristics of a controlling financial interest. FIN 46R requires that the company that is subject to a majority of the risk of loss from a variable interest entity's activities, or is entitled to receive a majority of the entity's residual returns, or both, consolidate the variable interest entity. A company that consolidates a variable interest entity is called the primary beneficiary.

PG&E Corporation and the Utility adopted FIN 46R on January 1, 2004. In accordance with FIN 46R, the Utility consolidated the assets, liabilities and non-controlling interests of two low-income housing partnerships that were determined to be variable interest entities under FIN 46R. The consolidation of these variable interest entities resulted in an increase in total assets and total liabilities of \$16 million. There was no impact on income resulting from the adoption of FIN 46R.

Low Income Housing Partnerships

The Utility is a limited partner in two low-income housing partnerships, or LIHPs, that are considered to be variable interest entities. The Utility was determined to be the primary beneficiary of both of these entities. The two partnerships were formed to invest in low-income housing projects sponsored by non-profit organizations in the state of California. The LIHPs have issued debt in the amount of \$8 million, which is secured by assets of the partnerships in the amount of \$28 million and the Utility's capital infusion commitments. In addition to the amounts recorded above, the Utility is required to make capital infusions of approximately \$16 million to the two LIHPs over the next five years.

The Utility has not applied FIN 46R to 11 other low-income housing partnership investments that are subsidiaries of one of the LIHPs. The Utility is unable to apply FIN 46R to these partnerships because it does not have the legal right to the information necessary to determine if these entities are variable interest entities or to perform the accounting required to consolidate the entities. The Utility's maximum exposure to loss from these partnership investments is the partnership's current investment of \$26 million.

Power Purchase Agreements

The Utility is unable to apply the provisions of FIN 46R to 28 entities that are counterparties of power purchase agreements. It is conceivable that the Utility could have a significant variable interest in a power purchase agreement counterparty if that entity is a variable interest entity and it owns one plant that sells substantially all of its output to the Utility, and the contract price for power is correlated with the plant's variable costs of production. The Utility was unable to obtain the information necessary to determine whether 28 of its power purchase agreement counterparties are variable interest entities or determine if the Utility is the primary beneficiary of these entities because the counterparties are not legally required to provide the Utility with the information.

These 28 entities 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. In regards to these 28 agreements, approximately 1,000 megawatts, or MW expire between 2004 and 2026 and approximately 143 MW have no specific expiration dates. Collective purchases from these entities were \$115 million for the three months ended March 31, 2004 and \$102 million for the three months ended March 31, 2003. The Utility has no investment at risk in the counterparty entities or commitment to fund losses.

Changes in Accounting for Certain Derivative Contracts

In November 2003 the FASB approved an amendment to an interpretation issued by the Derivatives Implementation Group C15 (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.

PG&E Corporation and the Utility had previously adopted the new DIG C15 guidelines prospectively for new derivative instruments entered into after June 30, 2003. On January 1, 2004, PG&E Corporation and the Utility adopted the new DIG C15 guidelines for certain power contracts that contain optionality that existed prior to July 1, 2003. The adoption of DIG C15 did not have any impact on the Consolidated Financial Statements of PG&E Corporation or the Utility.

Regulation and Statement of Financial Accounting Standards No. 71

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with "Accounting for the Effects of Certain Types of Regulation," as amended, or SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the costs of providing service. SFAS No. 71 applies to all of the Utility's operations except for a natural gas pipeline. As discussed further in Note 2, during the first quarter of 2004, the Utility began reapplying SFAS No. 71 to its generation operations. As a result, as of March 31, 2004, the Utility recorded a generation regulatory asset of approximately \$1.2 billion. 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 are written off.

Earnings (Loss) Per Share

As a result of the implementation of the Settlement Agreement and the related recognition of the regulatory assets, discussed in Note 2, at March 31, 2004, PG&E Corporation had retained earnings of approximately \$1.6 billion. Accordingly, basic earnings (loss) per share is calculated utilizing the "two-class" method by dividing earnings (loss) allocated to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings (loss) per share is computed by dividing net income (loss), adjusted for the net interest and the change in market value of dividend participation rights associated with the Convertible 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 earnings (loss) per share:

(in millions, except share amounts)	Three Months Ended March 31,	
	2004	2003
Income (loss) from continuing operations	\$ 3,033	\$ (83)
Discontinued operations	-	(265)
Net income (loss) before cumulative effect of changes in accounting principles	3,033	(348)
Cumulative effect of changes in accounting principles	-	(6)
Net income (loss) for basic calculations	3,033	(354)
Earnings (loss) allocated to common shareholders, basic	2,893	(354)
Earnings (loss) allocated to Convertible Notes, basic	140	-
Net income (loss)	3,033	(354)
9.50% Convertible Notes:		
Change in market value of dividend participation rights	19	-
Interest expense	4	-
Net income (loss) for diluted calculations	\$ 3,056	\$ (354)
Weighted average common shares outstanding, basic	393	382
Add: 9.50% Convertible Notes	19	-
Employee stock options and PG&E Corporation shares held by grantor trusts	7	-
PG&E Corporation Warrants	4	-
Rounding	1	-
Shares outstanding for diluted calculations	424	382
Earnings (Loss) Per Common Share, Basic		
Income (loss) from continuing operations	\$ 7.36	\$ (0.22)

Discontinued operations	-	(0.69)
Cumulative effect of changes in accounting principles	-	(0.02)
Net earnings (loss)	\$ 7.36	\$ (0.93)
Earnings (Loss) Per Common Share, Diluted		
Income (loss) from continuing operations	\$ 7.21	\$ (0.22)
Discontinued operations	-	(0.69)
Cumulative effect of changes in accounting principles	-	(0.02)
Net earnings (loss)	\$ 7.21	\$ (0.93)

No portion of the loss for the period ended March 31, 2003 was allocated to the participating security under the "two-class" method since there is no contractual obligation for these Convertible Notes to share in the losses of PG&E Corporation.

Diluted earnings per share for the three months ended March 31, 2003 excludes 19 million incremental shares related to the Convertible Notes, approximately one million incremental shares related to employee stock options and shares held by grantor trusts and four million incremental shares related to warrants and includes associated interest expense of \$4 million (net of income taxes of \$3 million) due to the anti-dilutive effect upon loss from continuing operations.

PG&E Corporation reflects the preferred dividends of subsidiaries as other expense for computation of both basic and diluted earnings per share.

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 Disclosure, an Amendment of FASB Statement No. 123," or SFAS No. 148. Under the intrinsic value method, PG&E Corporation and the Utility do not recognize any compensation expense for stock options, as the exercise price is equal to the fair market value of a share of PG&E Corporation common stock at the time the options are granted. If compensation expense had been recognized using the fair value-based method under SFAS No. 123, PG&E Corporation's pro forma consolidated earnings (loss) and earnings (loss) per share would have been as follows:

(in millions, except share amounts)	Three Months Ended March 31,	
	2004	2003
Net Earnings (Loss):		
As reported	\$ 3,033	\$ (354)
Deduct: Total stock-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(4)	(5)
Pro forma	\$ 3,029	\$ (359)
Basic earnings (loss) per share:		
As reported	\$ 7.36	\$ (0.93)
Pro forma	7.35	(0.94)
Diluted earnings (loss) per share:		
As reported	\$ 7.21	\$ (0.93)
Pro forma	7.20	(0.94)

If compensation expense had been recognized using the fair value-based method under SFAS No. 123, the Utility's pro forma consolidated earnings (loss) would have been as follows:

(in millions)	Three Months Ended March 31,	
	2004	2003
Net Earnings (Loss):		
As reported	\$ 3,066	\$ (79)
Deduct: Total stock-based employee compensation expense determined under		

the fair value based method for all awards, net of related tax effects	(2)	(2)
Pro forma	\$ 3,064	\$ (81)

At March 31, 2004, a total of 2,086,180 shares of restricted PG&E Corporation common stock had been awarded to eligible employees of PG&E Corporation and its subsidiaries, of which 1,278,140 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. In general, for shares 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 share price. For shares granted in 2004, the restrictions lapse automatically over a period of four years at the rate of 25% per year, and the compensation expense remains fixed at the value of the stock at grant date. Compensation expense associated with all the shares is recognized on a quarterly basis, by amortizing the unearned compensation related to that period.

Comprehensive Income (Loss)

PG&E Corporation's and the Utility's comprehensive income (loss) consists principally of changes in the market value of certain cash flow hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, or SFAS No. 133, and the effects of the remeasurement of the defined benefit pension plan.

	Three Months Ended March 31, 2004	
	PG&E Corporation	Utility
Net income available for common stock	\$ 3,033	\$ 3,066
Net gain in other comprehensive income (OCI)		
from current period hedging transactions and price changes in accordance with SFAS No. 133 (net of income tax expense of \$2 million)	3	3
Net reclassification from OCI to earnings	-	-
Foreign currency translation adjustment	-	-
Other	1	-
Total comprehensive income (loss)	\$ 3,037	\$ 3,069

	Three Months Ended March 31, 2003	
	PG&E Corporation	Utility
Net loss allocated to common stock	\$ (354)	\$ (79)
Net loss in OCI from current period hedging transactions and price changes in accordance with SFAS No. 133 (net of income tax benefit of \$1 million)	(1)	-
Net reclassification from OCI to earnings (net of income tax expense of \$47 million)	5	-
Foreign currency translation adjustment (net of income tax expense of \$2 million)	3	-
Total comprehensive loss	\$ (347)	\$ (79)

The above changes to OCI are stated net of income taxes benefits of \$2 million for the three-month period ended March 31, 2004, and \$48 million for the three-month period ended March 31, 2003.

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of an enterprise that results from transactions and other economic events other than transactions with shareholders. The following table sets forth the changes in each component of accumulated other comprehensive income (loss):

	Hedging Transactions in Accordance with SFAS No. 133	Foreign Currency Translation Adjustment	Retirement Plan Remeasurement	Other	Accumulated Other Comprehensive Income (Loss)
Balance at December 31, 2002	\$ (90)	\$ (3)	\$ -	\$ -	\$ (93)
Period change in:					
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	(1)	-	-	-	(1)
Net reclassification to earnings	5	-	-	-	5
Other	-	3	-	-	3
Balance at March 31, 2003	\$ (86)	\$ -	\$ -	\$ -	\$ (86)
Balance at December 31, 2003	\$ (81)	\$ -	\$ (4)	\$ -	\$ (85)
Period change in:					
Mark-to-market adjustments for hedging transactions in accordance with SFAS No. 133	3	-	-	-	3
Net reclassification to earnings	-	-	-	-	-
Other	-	-	-	1	1
Balance at March 31, 2004	\$ (78)	\$ -	\$ (4)	\$ 1	\$ (81)

Amounts included in accumulated other comprehensive income (loss) related to discontinued operations were \$77 million at March 31, 2004, and \$(86) million at March 31, 2003.

Income Taxes

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 \$17 million were recorded in discontinued operations, and \$5 million in accumulated other comprehensive loss for the three-month period ended March 31, 2003.

Upon deconsolidation of NEGT for financial statement purposes, PG&E Corporation adopted the cost method of accounting for its ownership interest in NEGT. As a result of this accounting change, PG&E Corporation will not recognize additional income tax benefits for financial statement reporting purposes after July 7, 2003, with respect to 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.

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 support services in support of operations. These services are priced either at the fully loaded cost (i.e., direct costs and allocation 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 a variety of factors, including the number of employees, operating expenses excluding fuel purchases, total assets and other cost-causal methods. The Utility purchases natural gas transportation services from Gas Transmission Northwest Corporation, or GTNW, formerly known as PG&E Gas Transmission, Northwest Corporation. Effective April 1, 2003, the Utility no longer purchases natural gas from NEGT Energy Trading Holdings Corporation, or NEGT ET, formerly known as PG&E Energy Trading Holdings Corporation. Both GTNW and NEGT ET are subsidiaries of NEGT. The Utility sold natural gas transportation capacity and other ancillary services to NEGT ET until NEGT's Chapter 11 proceeding was imminent. These services were priced at either tariff rates or fair market value, depending on the nature of the services provided. Through July 7, 2003, all significant intercompany transactions are eliminated in consolidation; therefore, no profit or loss resulted from these transactions. Beginning July 8, 2003, the Utility's transactions with NEGT are no longer eliminated in consolidation. The Utility's significant related party transactions and related receivable (payable) balances were as follows:

	Three Months Ended March 31,		Receivable (Payable) Balance Outstanding At	
(in millions)	2004	2003	March 31, 2004	December 31, 2003
Utility revenues from:				
Administrative services provided to PG&E Corporation	\$ 2	\$ 2	\$ 1	\$ -

Natural gas transportation capacity services provided to NEGT ET	-	3	-	-
Trade deposit due from GTNW	(15)	3	-	15
Utility expenses from:				
Administrative services received from PG&E Corporation	\$ 22	\$ 13	\$ (265)	\$ (396)
Interest accrued on pre-petition liability due to PG&E Corporation	2	2	(2)	(2)
Administrative services received from NEGT	-	1	-	(1)
Gas commodity services received from NEGT ET	-	10	-	-
Gas transportation services received from GTNW	15	15	(8)	(8)
Trade deposit due to NEGT ET	-	1	-	-

As discussed further in Note 2, as of March 31, 2004, PG&E Corporation recorded the impact of the Settlement Agreement. One of the terms of the Settlement Agreement precluded the Utility from reimbursing PG&E Corporation for certain Chapter 11-related costs. As such, PG&E Corporation reduced its receivable from the Utility, and the Utility reduced its payable to PG&E Corporation, by \$128 million. The transactions were recorded as a contribution to the Utility by PG&E Corporation, net of taxes of \$52 million, and an increase to additional paid-in capital by the Utility.

Pension and Other Postretirement Benefits

PG&E Corporation and its subsidiaries provide non-contributory defined benefit pension plans for certain of their employees and retirees (referred to collectively as pension benefits), contributory postretirement medical plans for certain of their employees and retirees and their eligible dependents, and non-contributory postretirement life insurance plans for certain of their employees and retirees (referred to collectively as other benefits). PG&E Corporation and its subsidiaries use a December 31 measurement date for all of its plans and 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.

Under SFAS No. 71, regulatory adjustments are 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 postretirement benefits for 1993 and beyond.

Net periodic benefit cost as reflected in PG&E Corporation's and the Utility's Statement of Operations for the three months ended March 31, 2004 and March 31, 2003 are as follows:

PG&E Corporation

(in millions)	Pension Benefits		Other Benefits	
	2004	2003	2004	2003
Service cost for benefits earned	\$ 47	\$ 41	\$ 9	\$ 8
Interest cost	118	114	23	20
Expected return on Plan's assets	(141)	(122)	(19)	(15)
Amortized prior service cost	14	14	9	7
Amortization of unrecognized loss	-	10	-	1
Net periodic benefit cost	\$ 38	\$ 57	\$ 22	\$ 21

Utility

(in millions)	Pension Benefits		Other Benefits	
	2004	2003	2004	2003
Service cost for benefits earned	\$ 46	\$ 40	\$ 9	\$ 8
Interest cost	117	113	23	20
Expected return on Plan's assets	(141)	(121)	(19)	(15)
Amortized prior service cost	15	14	9	7

Amortization of unrecognized loss	-	10	-	1
Net periodic benefit cost	\$ 37	\$ 56	\$ 22	\$ 21

The Utility previously disclosed in its Annual Report for the year ended December 31, 2003 that it expected to contribute up to \$129 million to its pension benefits plan, assuming favorable resolution of pension-related rate recovery in the 2003 general rate case, or GRC, in which it requested the CPUC to approve a related \$75 million additional revenue requirement. On April 6, 2004, the administrative law judge, or ALJ, issued a proposed decision in the 2003 GRC recommending rejection of the Utility's request. A final decision on pension funding for 2003 will be made upon receipt of the final GRC decision.

Accounting Pronouncements Issued But Not Yet Adopted

Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003

In March 2004, the FASB issued Staff Position SFAS No. 106-b, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," or SFAS No. 106-b. SFAS No. 106-b supersedes SFAS No. 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," and provides guidance on the accounting, disclosure, effective date and transition related to the Prescription Drug Act. Under the current proposal, SFAS No. 106-b is to become effective for the third quarter 2004, which begins on July 1, 2004. PG&E Corporation and the Utility are continuing to evaluate the impact of SFAS No. 106-b's recognition, measurement and disclosure provisions on their Consolidated Financial Statements.

NOTE 2: THE UTILITY CHAPTER 11 FILING

The discussion of the Utility's Chapter 11 filing matters below should be read in conjunction with Note 2 of the Notes to the Consolidated Financial Statements of PG&E Corporation's and the Utility's combined 2003 Annual Report filed with the Current Report on Form 8-K dated March 2, 2004.

Emergence From Chapter 11

On April 12, 2004, the Utility's Plan of Reorganization under Chapter 11 of the U.S. Bankruptcy Code became effective. The Plan of Reorganization incorporated the terms of the settlement agreement approved by the CPUC on December 18, 2003, and entered into among the CPUC, the Utility and PG&E Corporation on December 19, 2003, to resolve the Utility's Chapter 11 proceeding, or Settlement Agreement. Although the Utility's operations will no longer be subject to the oversight of the bankruptcy court, the bankruptcy court will retain jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Settlement Agreement, (2) the Plan of Reorganization, and (3) the bankruptcy court's December 22, 2003 order confirming the Plan of Reorganization. In addition, the bankruptcy court retains jurisdiction to resolve remaining disputed claims.

In anticipation of its emergence from Chapter 11, the Utility consummated its public offering of \$6.7 billion of first mortgage bonds, or First Mortgage Bonds, on March 23, 2004. Upon the effectiveness of the Plan of Reorganization, the Utility paid all valid claims, deposited funds into escrow accounts for the payment of disputed claims upon resolution, reinstated certain obligations, and paid other obligations. The following table summarizes the sources and uses of funds for these transactions:

(in millions)			
	Sources		Uses
First Mortgage Bonds	\$ 6,700	Payments to Creditors	\$ 8,394
Term Loans	799	Disputed Claims Escrow	1,843
Account Receivable Financing Facility	350		
Total Debt Financing	7,849		
Cash used to pay Claims	2,388		
Sources of Funds for Claims	10,237	Uses of Funds for Claims	10,237
Reinstated Pollution Control Bond-Related Obligations	814	Reinstated Pollution Control Bond-Related Obligations	814
Reinstated Preferred Stock	421	Reinstated Preferred Stock	421
Cash on Hand	225	Preferred Dividends	93
		Environmental Measures	10
		Transaction Costs	122
Total Sources of Funds	\$ 11,697	Total Uses of Funds	\$ 11,697

In connection with its emergence from Chapter 11, the Utility received investment grade issuer credit ratings of Baa3 from Moody's Investors Service, or Moody's, and BBB- from Standard & Poor's, or S&P.

Appeals of the bankruptcy court's order confirming the Plan of Reorganization are still pending in the U.S. District Court for the Northern District of California, or the District Court. These appeals were filed by the two CPUC commissioners who did not vote to approve the Settlement Agreement, or the dissenting commissioners, and a municipality. The District Court will set a schedule for briefing and argument of the appeals at a later date. In addition, on April 15, 2004, the City and County of San Francisco, or CCSF, and Aglet Consumer Alliance, or Aglet, each filed a petition with the California Court of Appeal seeking review of the CPUC's December 18, 2003 decision approving the Settlement Agreement and the CPUC's March 16, 2004 decision denying applications for rehearing of its December 18, 2003 decision. CCSF and Aglet allege that the Settlement Agreement violates California law, among other claims. CCSF requests the appellate court to hear and review the CPUC's decisions approving the Settlement Agreement and Aglet requests that the CPUC's decisions be overturned. PG&E Corporation and the Utility believe the petitions are without merit and should be denied. The Utility's answer in opposition to the petitions for review is due May 19, 2004.

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

The Utility believes that the uncertainty regarding the outcome of the pending appeals and petitions does not alter the assessment that the regulatory assets provided under the Settlement Agreement are probable of recovery in rates, as discussed below.

Financial Summary of the Settlement Agreement

In light of the satisfaction of various conditions to the implementation of the Plan of Reorganization, including the consummation of the public offering of First Mortgage Bonds, the receipt of investment grade credit ratings and final CPUC approval of the Settlement Agreement, the accounting probability standard required to be met under SFAS No. 71 in order for the Utility to recognize the regulatory assets provided under the Settlement Agreement (as described below) was met as of March 31, 2004. Therefore, the Utility recorded the \$2.2 billion, after-tax, regulatory asset established under the Settlement Agreement, or the Settlement Regulatory Asset, and \$0.7 billion, after-tax, for the Utility retained generation regulatory assets as summarized in the table below and discussed further in the paragraphs below:

(in millions)	Settlement Regulatory Asset	Utility Retained Generation Regulatory Assets	Total
Authorized, pre-tax, January 1, 2004	\$ 3,730	\$ 1,249	\$ 4,979
Less: amortization from January 1 to March 31	58	21	79
Recognition of regulatory assets, pre-tax, March 31, 2004	3,672	1,228	4,900
Deferred income taxes	1,496	500	1,996
Recognition of regulatory assets, after-tax, March 31, 2004	2,176	728	2,904
Less: offsets of supplier settlements, after-tax	8	-	8
Net, March 31, 2004	\$ 2,168	\$ 728	\$ 2,896

Settlement Regulatory Asset

- The Settlement Agreement established a \$2.2 billion, after-tax, regulatory asset (which is equivalent to an approximately \$3.7 billion, pre-tax, regulatory asset) as a new, separate and additional part of the Utility's rate base that is being amortized on a "mortgage-style" basis over nine years beginning January 1, 2004. Under this amortization methodology, annual after-tax collections of the Settlement Regulatory Asset are estimated to range from approximately \$140 million in 2004 to approximately \$380 million in 2012. This after-tax Settlement Regulatory Asset will be reduced for any refunds, claim offsets or other credits the Utility receives from energy suppliers relating to specified electricity procurement costs incurred during the California energy crisis, including those arising from the settlement of CPUC litigation against El Paso Natural Gas Company. As of March 31, 2004, the Utility recognized a one-time non-cash gain of \$3.7 billion, pre-tax, for the Settlement Regulatory Asset.
- The unamortized balance of the Settlement 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 the Settlement Regulatory Asset will be no less than 52% for the remaining term. If the Utility completes a refinancing of the Settlement Regulatory Asset supported by a dedicated rate component as discussed below, the equity and debt components of the Utility's rate of return will be replaced with the lower interest rate of the securitized debt.

Utility Retained Generation Regulatory Assets

- In the Settlement Agreement, the CPUC deemed the Utility's adopted electricity generation rate base in a 2002 proceeding to be just and reasonable and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. Accordingly, as of March 31, 2004 the Utility recognized a one-time non-cash gain of \$1.2 billion, pre-tax, for the retained generation regulatory assets. The individual components of the regulatory assets will be amortized over their respective lives, with a weighted average life of approximately 16 years.

Ratemaking Matters

- In the Settlement Agreement, the CPUC agreed to set the Utility's capital structure and authorized return on equity in its annual cost of capital proceedings in its usual manner. However, from January 1, 2004 until Moody's has issued an issuer rating for the Utility of not less than A3 or S&P has issued a long-term issuer credit rating for the Utility of not less than A-, the Utility's authorized return on equity will be no less than 11.22% per year and its authorized equity ratio for ratemaking purposes will be no less than 52%. 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 CPUC also agreed to act promptly on certain of the Utility's pending ratemaking proceedings, including the Utility's pending 2003 GRC. The outcome of these proceedings may result in the establishment of additional regulatory assets on the Utility's Consolidated Balance Sheets.

Environmental Measures

- In the Settlement Agreement, the Utility agreed to encumber with conservation easements or donate approximately 140,000 acres of land to public agencies or non-profit conservation organizations.
- The Utility has established PG&E Environmental Enhancement Corporation as a California non-profit corporation to oversee the environmental enhancements associated with these lands. The Utility has agreed to fund the corporation with \$100 million in cash over ten years, although the Utility will be entitled to recover these payments in rates. At March 31, 2004, the Utility recorded an \$83 million regulatory asset and associated liability based on the discounted present value of future cash payments. On April 12, 2004, the Utility made its first \$10 million installment payment to this corporation.
- The Utility has also agreed to establish a California non-profit corporation dedicated to support research and investment in clean energy technology, primarily in the Utility's service territory. The Utility has agreed to fund this corporation with \$30 million payable over five years beginning in January 2005. These contributions may not be recovered in rates. At March 31, 2004, the Utility recorded a \$27 million pre-tax charge to earnings based on the discounted present value of future cash payments.

Of the approximately 140,000 acres referred to above, approximately 44,000 acres may be either donated or encumbered with conservation easements. The remaining land contains the Utility's or a joint licensee's hydroelectric generation facilities and may only be encumbered with conservation easements. At March 31, 2004, the Utility recorded a \$1 million pre-tax charge to earnings associated with the land donation obligation.

Fees and Expenses

The Settlement Agreement required the Utility to reimburse the CPUC for its professional fees and expenses incurred in connection with the Chapter 11 proceeding. These amounts will be recovered from customers over a reasonable time of up to four years. At March 31, 2004, the Utility recorded a regulatory asset and associated liability of approximately \$30 million for the CPUC reimbursable fees and expenses. In addition, one of the terms of the Settlement Agreement precluded the Utility from reimbursing PG&E Corporation for certain Chapter 11-related costs. As such, PG&E Corporation reduced its receivable from the Utility, and the Utility reduced its payable to PG&E Corporation, by \$128 million. The transactions were recorded as a contribution to the Utility by PG&E Corporation, net of taxes, and an increase to additional paid-in capital by the Utility.

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 Settlement 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 Settlement 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 Settlement 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. Upon refinancing with securitization, the equity and debt components of the Utility's rate of return on the Settlement 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.

On January 22, 2004, the CPUC approved proposed legislation, Senate Bill 772, which would authorize a dedicated rate component to securitize the Settlement Regulatory Asset and the related taxes. The California legislature has been considering the proposed legislation and it may be presented for signature by the Governor as soon as the end of May 2004.

Chapter 11 Claims

Claims filed in the Chapter 11 proceeding totaled approximately \$51.7 billion. Of these claims, approximately \$9.8 billion related to California Independent System Operator, or ISO, Power Exchange, or PX, and generator claims. Under a bankruptcy court order the aggregate allowable amount of ISO, PX and generator claims was limited to approximately \$1.6 billion after giving effect to approximately \$200 million in pre-petition offset. The Utility expects that this amount will be further reduced as a result of certain proceedings pending at the FERC. Of the approximately \$43.5 billion of filed claims, including the limited amount of ISO, PX and generator claims of approximately \$1.6 billion, approximately \$24.3 billion was disallowed by the bankruptcy court due to objections, claim withdrawals and agreements with claimants. The Utility has objected to approximately \$1.1 billion of the remaining approximately \$19.2 billion of filed claims. In addition, certain claims, including those related to environmental, pending litigation and tort claims, aggregating approximately \$4.7 billion of the remaining \$19.2 billion of filed claims, have passed through the bankruptcy. The Utility has analyzed these pass-through claims and has recorded reserves for such claims that are included in the Utility's undiscounted environmental remediation liability of approximately \$337 million at March 31, 2004 and the Utility's provision for legal matters of \$191 million at March 31, 2004, as discussed below in Note 6. At March 31, 2004, the Utility had made approximately \$2.3 billion in claims-related principal payments and settled additional claims of approximately \$300 million with the cancellation of certain bonds owned by the Utility.

The Utility has recorded its estimate of all valid claims at March 31, 2004 as approximately \$9.2 billion of liabilities subject to compromise (including interest on claims) and approximately \$2.4 billion of long-term debt. At December 31, 2003, the Utility had recorded approximately \$9.5 billion of liabilities subject to compromise and approximately \$2.7 billion of long-term debt. Upon the effectiveness of the Plan of Reorganization, the Utility paid approximately \$8.4 billion in cash to holders of allowed claims and deposited approximately \$1.8 billion into escrow accounts for the payment of disputed claims, which is approximately equal to the amounts accrued as liabilities for these claims at that date (see the sources and uses of funds table as discussed above in the "Emergence From Chapter 11" section).

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:

(in millions)	Balance At	
	March 31, 2004	December 31, 2003
PG&E Corporation		
Senior secured notes, 6 7/8%, due 2008	\$ 600	\$ 600
Convertible subordinated notes, 9.50%, due 2010	280	280
Other long-term debt	3	3
Total long-term debt	883	883
Utility		
First and refunding mortgage bonds:		
5.85% to 8.80% bonds, maturing 2004-2026	2,454	2,764
Unamortized discount net of premium	(23)	(23)
Total first and refunding mortgage bonds	2,431	2,741
First mortgage bonds		
1.81% to 6.05% bonds, maturing 2006-2034	6,700	-
Unamortized discount net of premium	(18)	-
Total first mortgage bonds	6,682	-
Other ⁽¹⁾	8	-
Less current portion ⁽¹⁾	(4)	(310)
Total long-term debt, net of current portion	9,117	2,431
Total consolidated long-term debt, net of current portion	\$ 10,000	\$ 3,314
Long-term debt subject to compromise:		
Senior notes, 10.75%, 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, 6.94% to 9.58%, due 2004-2014	287	287
Deferrable interest subordinated debentures, 7.90%, due 2025	300	300
Other	17	17
Total long-term debt subject to compromise	\$ 2,098	\$ 2,098

- (1) Other includes debt of two low-income housing partnerships that have been consolidated on adoption of FIN 46R. At March 31, 2004, \$7.3 million of the debt was in default due to the Utility's Chapter 11 filing. When the Utility emerged from Chapter 11 on April 12, 2004, this default was cured.

Utility

In March 2004, in connection with the implementation of the Plan of Reorganization, the Utility issued \$6.7 billion of First Mortgage Bonds and, together with its consolidated subsidiaries, entered into \$2.9 billion of credit facilities. The Utility also obtained an interim \$400 million cash collateralized letter of credit facility, which was terminated on April 12, 2004, the effective date of the Plan of Reorganization, or the Effective Date, and the letters of credit outstanding were transferred to the \$850 million revolving credit facility.

First Mortgage Bonds

On March 23, 2004, the Utility closed a public offering of \$6.7 billion of First Mortgage Bonds. The First Mortgage Bonds were offered in multiple tranches consisting of 3.60% First Mortgage Bonds due March 1, 2009 in the principal amount of \$600 million, 4.20% First Mortgage Bonds due March 1, 2011 in the principal amount of \$500 million, 4.80% First Mortgage Bonds due March 1, 2014 in the principal amount of \$1 billion, 6.05% First Mortgage Bonds due March 1, 2034 in the principal amount of \$3 billion, and Floating Rate First Mortgage Bonds due April 3, 2006 in the principal amount of \$1.6 billion. The Utility received proceeds of \$6.7 billion from the offering, net of a discount of \$18 million. The interest rate for the Floating Rate Mortgage Bonds is based on the three-month LIBOR, plus 0.70%, that will reset quarterly beginning on July 3, 2004.

In addition, approximately \$2.5 billion of additional First Mortgage Bonds were used on the Effective Date to secure the Utility's credit facilities as described below and to secure the Utility's reimbursement obligation under an insurance policy relating to certain pollution control bonds that were issued for the benefit of the Utility.

The First Mortgage Bonds are secured by a first priority lien on substantially all of the Utility's real property and certain tangible personal property related to the Utility's facilities. Subject to certain conditions, the Utility will be entitled to terminate the lien and eliminate all terms and conditions relating to collateral for the First Mortgage Bonds on the release date. In general, the release date will occur when the Utility provides written evidence to the trustee of the First Mortgage Bonds that the ratings on the Utility's long-term unsecured debt obligations following the release date would at least equal the initial ratings assigned by Moody's and S&P on the First Mortgage Bonds or, if either or both of these rating agencies do not then rate the Utility's long-term unsecured debt obligations, comparable ratings by any other nationally recognized rating agency or agencies selected by the Utility. The First Mortgage Bonds received initial investment grade credit ratings of Baa2 from Moody's and BBB from S&P.

At the time of the closing of the offering of the First Mortgage Bonds, the Plan of Reorganization was not yet effective. Therefore, the Utility deposited the proceeds of the sale of the First Mortgage Bonds into an escrow account. See Note 2, "The Utility's Chapter 11 Filing," for additional information concerning the use of proceeds of the sale of the First Mortgage Bonds. On March 31, 2004, the amount in the escrow account was classified as restricted cash in non-current assets on the Utility's Consolidated Balance Sheet.

Repayment Schedule

The following table details the scheduled maturities of the Utility's long-term debt outstanding at March 31, 2004, excluding the Utility's first and refunding mortgage bonds and debt subject to compromise that were repaid on the Effective Date.

(in millions)	2004	2005	2006	2007	2008	Thereafter	Total
Long-term debt:							
Fixed rate obligations	\$ -	\$ -	\$ -	\$ -	\$ -	\$ 5,082	\$ 5,082
Average interest rate	-%	-%	-%	-%	-%	5.34%	5.34%
Variable rate obligations	-	-	1,600	-	-	-	1,600
Other	4	2	1	-	-	1	8
Rate reduction bonds	216	290	290	290	-	-	1,086
Average interest rate	6.42%	6.42%	6.44%	6.48%	-%	-%	6.44%
Total	\$ 220	\$ 292	\$ 1,891	\$ 290	\$ -	\$ 5,083	\$ 7,776

Credit Facilities and Short-Term Borrowings

The following table summarizes the Utility's lines of credit and short-term borrowings subject to compromise, which were paid and cancelled on the Effective Date, and credit facilities that the Utility and its consolidated subsidiaries entered into on March 5, 2004. PG&E Corporation does not maintain credit facilities or short-term borrowings.

(in millions)	April 12, 2004	Balance At March 31, 2004	December 31, 2003
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:			
Accounts receivable financing	\$ 350	\$ -	\$ -
Pollution control bonds reimbursement agreements	620	-	-
Pollution control bonds term loans	345	-	-
Amended and restated reimbursement agreements	454	-	-
Total credit facilities	\$ 1,769	\$ -	\$ -

On March 5, 2004, the Utility and its consolidated subsidiaries entered into credit facility agreements totaling approximately \$2.9 billion. The credit facilities consist of the following:

Accounts Receivable Financing

On March 5, 2004, the Utility entered into certain agreements providing for the continuous sale of a portion of the Utility's accounts receivable to PG&E Accounts Receivable Company LLC, or PG&E ARC, a limited liability company wholly owned by the Utility. In turn, PG&E ARC will sell interests in its accounts receivable to commercial paper conduits or banks. PG&E ARC may obtain up to \$650 million of financing under such agreements. Unless extended, the credit facility will terminate on March 5, 2007. The credit facility may be extended for additional periods under the agreement of all parties. The Utility began selling accounts receivables to PG&E ARC on the Effective Date and used approximately \$350 million that was received from the sale of the accounts receivable in connection with this credit facility to pay allowed claims on the Effective Date. While PG&E ARC is a wholly owned consolidated subsidiary of the Utility, PG&E ARC is legally separate from the Utility. The assets of PG&E ARC (including the accounts receivables) are not available to creditors of the Utility or PG&E Corporation, and the accounts receivables are not legally assets of the Utility or PG&E Corporation. For the purposes of financial reporting, the facility is accounted for as a secured financing.

The accounts receivable facility includes customary covenants on the Utility's part and on the part of PG&E ARC, including covenants related to:

- Servicing of the accounts receivables in accordance with the Utility's credit and collection policy;
- Protecting the interests of the purchasers of the accounts receivable;
- Maintenance of any governmental authorization or approval necessary in connection with the operation of the Utility's business; and
- Indemnification of the purchasers.

Pollution Control Bonds Reimbursement Agreements

On March 5, 2004, the Utility entered into four separate reimbursement agreements under which the issuing lender issued, on the Effective Date, approximately \$620 million in new letters of credit to support approximately \$614 million aggregate principal amount of pollution control bonds that were previously issued for the benefit of the Utility.

The covenants under the pollution control bond reimbursement agreements are substantially the same as those of the working capital facility, as described below. On the Effective Date, the Utility secured its obligation under the four separate reimbursement agreements with First Mortgage Bonds.

Pollution Control Bonds Term Loans

On March 5, 2004, the Utility entered into a term loan facility of \$345 million that was used to fund the purchase, in lieu of redemption, of certain pollution control bonds on the Effective Date, which is due and payable on June 5, 2005. At the Utility's request and at the sole discretion of each lender, the term loan facility may be extended for additional periods.

The covenants under the term loan facility are substantially the same as those of the working capital facility, as described below. On the Effective Date, the Utility secured its obligation under the term loan facility with First Mortgage Bonds.

Amended and Restated Reimbursement Agreements

During the course of the Utility's Chapter 11 proceeding, approximately \$454 million in the aggregate principal amount of pollution control bonds, which were issued for the Utility's benefit, were redeemed through draws on letters of credit, giving rise to an obligation to reimburse the issuers of these letters of credit or their respective assignees for the amounts drawn. On the Effective Date, the Utility amended the four separate reimbursement agreements and restated them after the lenders had purchased the \$454 million in reimbursement obligations owed to the issuers of the drawn letters of credit or their respective assignees. The Utility expects to repay the amounts outstanding under the amended and restated reimbursement agreements through the issuance of new refunding pollution control bonds or otherwise. The outstanding balance of \$454 million under the amended and restated reimbursement agreements is due and payable on June 5, 2005. At the Utility's request and at the sole discretion of each lender, each amended and restated reimbursement agreement may be extended for additional periods.

The covenants under each amended and restated reimbursement agreement are substantially identical to those of the working capital facility, as described below. On the Effective Date, the Utility secured its obligations under the amended and restated reimbursement agreements with First Mortgage Bonds.

Working Capital Facility

On March 5, 2004, the Utility entered into an \$850 million revolving credit facility, or working capital facility, with a syndicate of banks. Loans under the working capital facility will be used primarily to cover operating expenses and seasonal fluctuations in cash flows. Letters of credit under the working capital facility will be used primarily to provide credit enhancements to counterparties for natural gas and electricity procurement transactions. The working capital facility has a term of three years and all outstanding amounts will be due and payable on March 5, 2007. At the Utility's request and at the sole discretion of each lender, the working capital facility may be extended for additional periods. On the Effective Date, the Utility secured its obligation under the working capital facility with First Mortgage Bonds. On the Effective Date, approximately \$206 million of letters of credit from a cash collateralized \$400 million letter of credit facility was transferred to the working capital facility with no loans outstanding under the working capital facility.

The working capital facility includes customary covenants, including covenants related to:

- Maintenance, as of the end of each fiscal quarter ending after the Effective Date, of a debt to capitalization ratio of at most 0.65 to 1.00;
- Prohibition on the disposition of assets, other than dispositions of inventory and obsolete property in the ordinary course, in excess of 25% of the aggregate book value of the Utility's and the Utility's significant subsidiaries' assets at December 31, 2003;
- A limitation on liens no more restrictive than the limitation on liens that becomes effective under the indenture from and after the release date;
- Limitation on mergers and sales of all or substantially all of the Utility's assets; and
- Maintenance of any governmental authorization or approval necessary in connection with the operation of the Utility's business.

Cash Collateralized Letter of Credit

In addition to the \$2.9 billion in credit facilities, on March 2, 2004, the Utility entered into a cash collateralized \$400 million letter of credit facility that was used to issue letters of credit to provide credit support in connection with the Utility's preexisting and new natural gas procurement activities and related purchases of natural gas transportation services. This credit facility was terminated on the Effective Date, and the outstanding balance of approximately \$206 million of letters of credit outstanding was transferred to the \$850 million working capital facility.

NOTE 4: DISCONTINUED OPERATIONS

On July 8, 2003, NEGT filed a voluntary petition for relief under Chapter 11. The combination of the decline in wholesale electricity prices, the financial commitments related to NEGT's construction program, the decline of NEGT's credit rating to below investment grade, and the lack of market liquidity created severe financial distress and ultimately caused NEGT 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 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 periods.

Effective July 8, 2003, NEGT and its subsidiaries are no longer consolidated by PG&E Corporation in its Consolidated Financial Statements. The accompanying March 31, 2004 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 charge of approximately \$77 million at December 31, 2003 related to NEGT. The accompanying Consolidated Statements of Operations of PG&E Corporation for the three months ended March 31, 2003 present the operations of NEGT as discontinued operations. 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, 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. This amount will be reduced by any potential liability for NEGT claims related to contractual obligations, if any. 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. On May 3, 2004, NEGT's plan of reorganization was confirmed by the bankruptcy court. The plan of reorganization is expected to become effective during the second quarter of 2004. The effective date is contingent upon certain conditions being met within 90 days following the plan confirmation.

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:

(in millions)	Three Months Ended March 31, 2003
Operating revenues ⁽¹⁾	\$ 664
Loss before income taxes ⁽¹⁾	(421)
Net income ⁽¹⁾	(271)

⁽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 March 31, 2003 and the other previously discontinued operations through the respective disposal dates. The first quarter 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, and 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. Also included in the first quarter 2003 pre-tax loss are impairments, write-offs, and other charges of approximately \$199 million.

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 5: PRICE RISK MANAGEMENT

As discussed in Note 4, NEGТ financial results are no longer consolidated with those of PG&E Corporation following the July 8, 2003 Chapter 11 filing of NEGТ. NEGТ's financial results through July 7, 2003 are reflected in discontinued operations. Because NEGТ 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.

Convertible Subordinated Notes

PG&E Corporation currently has outstanding \$280 million of Convertible Notes, that are scheduled to mature on June 30, 2010. These Convertible Notes may be converted into 18,558,655 shares of common stock of PG&E Corporation. In addition, the terms of the Convertible Notes also entitle the note holders to participate in any dividend payments (non-cumulative) based on their equity conversion value.

In accordance with SFAS No. 133, the above dividend participation rights component is considered to be an embedded derivative instrument and, therefore, must be marked-to-market through earnings and its fair value must be reflected on the balance sheet. At March 31, 2004, the estimated fair value of the dividend participation rights component was \$19 million (net of taxes), which was reflected in PG&E Corporation's Consolidated Statement of Operations as a non-operating expense and as a noncurrent liability (Other Liabilities) on PG&E Corporation's Consolidated Balance Sheet. In the periods leading up to March 31, 2004, the fair value of the dividend participation rights component was immaterial.

Non-Trading Activities

On the Utility's Consolidated Balance Sheets, cash flow hedges associated with interest rate risk are presented at fair value in other current assets. For hedges associated with regulated operations and subject to the provisions of SFAS No. 71, the effective and ineffective portions are recorded in regulatory assets. At March 31, 2003, the Utility did not have any cash flow hedges.

The Utility has certain non-trading derivative instruments for the purchase of electricity, and natural gas transportation and storage that are either exempt from the SFAS No. 133 fair value requirements under the normal purchases and sales exception or are not derivative instruments and, therefore, have no mark-to-market effect on earnings. Additionally, the Utility holds 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. The fair value of these derivative instruments is recorded in other current assets or liabilities offset by regulatory liabilities or assets.

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 \$2.1 billion at March 31, 2004 and approximately \$2.5 billion at December 31, 2003. The majority of the accounts receivable are associated with the Utility's residential and small commercial customers. Based upon historical experience and evaluation of then-current factors, allowances for doubtful accounts of approximately \$61 million at March 31, 2004 and approximately \$68 million at December 31, 2003 were recorded against those accounts receivable. In accordance with tariffs, credit risk exposure is limited by requiring deposits from new customers and from those customers whose past payment practices are below standard. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in northern and central California. However, material loss due to non-performance from these customers is not considered likely.

The Utility manages credit risk for its wholesale customers and counterparties by assigning credit limits based on an evaluation of their financial condition, net worth, credit rating and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored frequently and a detailed credit analysis is performed at least annually.

Credit exposure for the Utility's wholesale customers and counterparties is calculated daily. If exposure exceeds the established limits, the Utility takes immediate action to reduce the exposure or obtain additional collateral, or both. Further, the Utility relies heavily on master agreements that require security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

The Utility calculates gross credit exposure for each of its wholesale customers and counterparties as the current mark-to-market value of the contract (*i.e.* , the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, before the application of credit collateral. During the first three months of 2004, the Utility recognized no material losses due to contract defaults or bankruptcies. At March 31, 2004, there were three counterparties that represented greater than 10% of the Utility's net credit exposure. The Utility had three investment grade counterparties that represented a total of approximately 53% of the Utility's net credit exposure.

The Utility conducts business with wholesale counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. This concentration of counterparties may impact the Utility's overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions.

The schedule below summarizes the Utility's net asset credit risk exposure, as well as the Utility's credit risk exposure to its wholesale customers or counterparties with a greater than 10% net credit exposure, at March 31, 2004 and December 31, 2003.

(in millions)	Gross Credit Exposure Before Credit Collateral ⁽¹⁾	Credit Collateral	Net Credit Exposure ⁽²⁾	Number of Wholesale Customers or Counterparties >10%	Net Exposure to Wholesale Customers or Counterparties >10%
March 31, 2004	\$ 160	\$ 16	\$ 144	3	\$ 77
December 31, 2003	165	11	154	3	68

(1) Gross credit exposure equals mark-to-market value, notes receivable and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value, liquidity or credit reserves. The Utility's gross credit exposure includes wholesale activity only. Retail activity and payables 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 wholesale customers and counterparties at March 31, 2004 and December 31, 2003:

(in millions)	Net Credit Exposure ⁽²⁾	Percentage of Net Credit Exposure
Credit Quality ⁽¹⁾		
March 31, 2004		
Investment grade ⁽³⁾	\$ 138	96%
Non-investment grade	6	4%

Total	\$ 144	100%
December 31, 2003		
Investment grade ⁽³⁾	\$ 108	70%
Non-investment grade	46	30%
Total	\$ 154	100%

- (1) Credit ratings are determined by using publicly available information. If provided a guarantee by a higher rated entity (e.g ., an affiliate), the rating is determined based on the rating of the guarantor.
- (2) Net credit exposure is the gross credit exposure minus credit collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.
- (3) Investment grade is determined using publicly available information, i.e. , rated at least Baa3 by Moody's and BBB- by S&P. The Utility has assessed certain governmental authorities that are not rated through publicly available information as investment grade based upon an internal assessment of credit worthiness.

NOTE 6: 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's and the Utility's commitments are discussed more fully in their combined 2003 Annual Report filed with the Current Report on Form 8-K dated March 2, 2004. The following summarizes PG&E Corporation's and the Utility's material contingencies and canceled, new, and significantly modified commitments since the combined 2003 Annual Report filed with the Current Report on Form 8-K dated March 2, 2004, was filed.

Commitments

Utility

Power Purchase Agreements

During the first quarter of 2004, the Utility entered into various agreements to purchase energy. Under these agreements, the Utility is committed to make energy payments of approximately \$52 million and capacity payments of approximately \$19 million in 2004.

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 have fluctuated generally based on market conditions.

As a result of the Utility's Chapter 11 filing and its credit rating being below investment grade, the Utility had used several different credit arrangements to purchase natural gas, including a \$10 million cash collateralized standby letter of credit and a pledge of its core natural gas customer accounts receivable. On March 2, 2004, these pledge facilities were replaced with a \$400 million limited cash collateralized letter of credit facility, or gas procurement letter of credit facility. The gas customer accounts receivable program terminated effective March 29, 2004. At March 31, 2004, amounts secured by this gas procurement letter of credit facility totaled approximately \$203 million. Upon emergence from Chapter 11 the Utility canceled this gas procurement letter of credit facility and transferred the outstanding balance to an \$850 million revolving credit facility backed by the Utility's new credit facilities.

At March 31, 2004, the Utility's obligations for natural gas purchases and gas transportation services were as follows:

(in millions)

2004	\$ 678
2005	168
2006	26
2007	7
2008	-
Thereafter	-
Total	\$ 879

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 March 31, 2004, the ISO had RMR agreements for which the Utility could be obligated to pay the ISO an estimated \$666 million in net costs during the period April 1, 2004, to March 31, 2006. 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 ALJ 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.

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 became effective April 20, 2004. On April 23, 2004, the Utility paid Enron cash of \$309 million, plus interest of approximately \$41 million. These payments have been reflected in the sources and uses of funds table in Note 2. As a result of the Enron Settlement, the Utility will receive an after-tax credit of approximately \$114 million that will reduce the Settlement Regulatory Asset and other regulatory balancing accounts. In the rate design settlement approved by the CPUC on February 26, 2004, the Utility's revenue requirement related to the amortization of the Settlement Regulatory Asset has been reduced to reflect an estimate of the after-tax credit included in the Enron Settlement. The CPUC decision approving the rate design settlement provides for regulatory balancing account treatment to ensure that the amount of the revenue requirement reduction is adjusted to reflect the net after-tax amounts actually received by the Utility under settlements with energy suppliers, including Enron.

Contingencies

The Utility has significant gain and loss contingencies, which are discussed below.

2003 General Rate Case

On April 6, 2004, a proposed decision was issued in the Utility's 2003 GRC pending at the CPUC. The 2003 GRC 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 for 2003 and succeeding years. The ALJ's proposed decision, excluding changes in attrition rate adjustments, would approve essentially all of the provisions contained in the July 2003 and September 2003 settlement agreements reached among the Utility and various consumer groups to set the Utility's 2003 revenue requirements for its electricity generation and electricity and natural gas distribution operations.

If the proposed decision is adopted by the CPUC, the Utility's total 2003 revenue requirements, as provided in the settlement agreements, would be set at approximately:

- \$2.5 billion for electricity distribution operations, representing a \$236 million increase over the previously authorized amount;
- \$927 million for natural gas distribution operations, representing a \$52 million increase over the previously authorized amount; and
- \$912 million for electricity generation operations, representing a \$38 million increase over the previously authorized amount.

In addition, under the proposed decision, if the Utility forecasts a second refueling outage at the Diablo Canyon nuclear power plant in any one year, the electricity generation revenue requirement would be increased to reflect a fixed revenue requirement of \$32 million per refueling outage, adjusted for changes in the Consumer Price Index, or CPI, in the manner described in the proposed decision. The only forecasted second refueling outage will occur in 2004.

The proposed decision would reject the Utility's request for approximately \$75 million in additional revenue requirements to fund a

pension contribution. If adopted, the proposed decision would be retroactive to January 1, 2003.

Because the CPUC has not yet issued a final decision on the Utility's 2003 GRC, the Utility has not included the natural gas distribution revenue requirement increase in its 2003 or 2004 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 \$123 million, which incorporated the impact of the electric portion of the GRC settlement. The Utility has recorded a regulatory liability for the refund obligation. If the 2003 revenue requirement that is ultimately approved in the Utility's 2003 GRC is lower than the amounts described above, the regulatory liability would increase. In 2004, the Utility began recording its base revenue requirements under a cost of service ratemaking structure. In the first quarter of 2004, the Utility collected less than its currently authorized base revenue requirements as approved in its 1999 GRC and 2001 attrition filings. The Utility has recorded the difference between its current base revenue requirement and the amount it has collected through cost of service rates in newly established electricity balancing accounts. The Utility has not included the impact of the electricity distribution revenue requirement increases in its results of operations for the first quarter of 2004. If the CPUC approves a revenue requirement increase in 2004, the Utility would record the increase in the results of operations for 2004.

The proposed decision is scheduled to be considered by the CPUC on May 6, 2004. A final decision is expected in the second quarter of 2004. If the proposed decision is approved, as written in the second quarter, the Utility would record regulatory assets and liabilities associated with the revenue requirement increases (including attrition), recovery of unfunded taxes, depreciation, and decommissioning. The net impact of these items is anticipated to result in pre-tax earnings of approximately \$400 million.

Also, on April 6, 2004, the CPUC issued a separate proposed decision to address an agreement between the Utility and the CPUC's Office of Ratepayer Advocates, or ORA, relating to the Utility's response to storm outages and other reliability issues and an agreement the Utility reached with the California Coalition of Utility Employees that proposed a reliability performance incentive mechanism for the Utility beginning in 2004 and continuing through 2009. Among other things, the CPUC accepted the reliability standards proposed by the Utility and ORA and approved certain reliability improvement initiatives as well as the funding for these initiatives, but rejected the proposed incentive mechanism.

PG&E Corporation and the Utility are unable to predict whether these proposed decisions will be adopted by the CPUC. If the CPUC does not approve the settlement agreements, the Utility's ability to earn its authorized rate of return for the years until the next GRC would be adversely affected. As previously discussed, the rate changes implemented during the first quarter of 2004 contemplated approval for the 2003 GRC consistent with the settlement agreements. To the extent that the final GRC is different from the settlement agreements, rates will be true-up.

PX Block-Forward Contracts

The Utility had PX block-forward contracts, which were seized by California's then-Governor Gray Davis in February 2001 for the benefit of the state, acting under California's Emergency Services Act. The block-forward contracts had an estimated unrealized gain of up to \$243 million at the time the state of California seized them. The Utility, the PX, and some of the PX market participants have filed claims in state court against the state of California to recover the value of the seized contracts; the state of California disputes the plaintiff's valuations. The estimated value of the seized contracts has been fully reserved in the Utility's financial statements. This state court litigation is pending.

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 premiums of up to \$40.2 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 \$10.8 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of \$300 million for the Diablo Canyon power plant. The balance of the \$10.8 billion of liability protection is covered by a loss-sharing program (secondary financial protection) among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of 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, which had coverage before December 31, 2003. Congress may address renewal of the Price-Anderson Act in future energy legislation.

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

Workers' Compensation Security

The Utility is self-insured for workers' compensation. 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 March 31, 2004, 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 March 31, 2004, 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.

On emergence from Chapter 11, PG&E expects to be eligible to participate in the Alternative Security Program, or ASP, administered by California's Self-Insurers' Security Fund, or SISF. PG&E was ineligible to participate in the ASP while in Chapter 11. The ASP is a program that allows the SISF to arrange a composite deposit for eligible self-insureds on a portfolio basis, rather than individual self-insurers arranging their deposits individually. SISF arranges portfolio security to be delivered to DIR for the aggregate self-insured workers' compensation liabilities for participating self-insurers. The Utility's participation in the ASP will result in the release of the \$348 million collateral that existed at March 31, 2004.

El Paso Settlement

In June 2003, the Utility, along with SCE, the state of California and 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 reduction of approximately \$125 million in El Paso's long-term electricity supply contracts with the California Department of Water Resources, or 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 net-after-tax amount of any consideration that the Utility actually receives in cash related to the electricity refunds will reduce the outstanding balance of the Settlement Regulatory Asset. The settlement was approved by the FERC in November 2003 and by the San Diego Superior Court in December 2003. An appeal of the attorney's fees award to class action plaintiffs' counsel in the litigation is pending, but that appeal will not affect the effectiveness of the settlement. The Superior Court's approval of the settlement is now final and is no longer subject to appeal. The refunds will be released from the escrow account when the settlement becomes effective according to its terms. The Utility believes it is probable that all conditions precedent to the effectiveness of the settlement will be satisfied soon.

Williams Settlement

On February 24, 2004, the Utility and SCE entered into a settlement agreement with The Williams Companies, or Williams settlement, settling certain pre-petition claims in the Utility's Chapter 11 proceeding. In order for the settlement to become effective, it must first be approved by the CPUC as to SCE, and the FERC. If the Williams settlement is approved, the Utility will receive an after-tax credit of approximately \$41 million that will reduce the Settlement Regulatory Asset and other regulatory balancing accounts. Certain settlement issues are still being resolved and could impact the amount the Utility ultimately receives. The CPUC decision approving the rate design settlement provides for regulatory balancing account treatment to ensure that the amount of the revenue requirement reduction is adjusted to reflect the amounts actually received by the Utility under pending settlements with energy suppliers, including The Williams Companies.

Dynegy Settlement

In April 2004, the Utility, along with SCE, San Diego Gas and Electric Company, the People of the State of California, and a number of other parties, entered into a settlement agreement with Dynegy Inc., or Dynegy, which resolves alleged overcharge and market manipulation claims from the sale of electricity by Dynegy into the California market during the California energy crisis. In order for this settlement to become effective, it must first be approved by the CPUC and the FERC. If the Dynegy settlement is approved, the Utility estimates it will receive an after-tax credit of approximately \$50 million that will reduce the Settlement Regulatory Asset and other regulatory balancing

accounts. The exact amount of the after-tax credit will depend upon the final determination made by the FERC in the pending refund proceeding discussed below under "FERC Prospective Price Mitigation Relief" below. The CPUC decision approving the rate design settlement provides for regulatory balancing account treatment to ensure that the amount of the revenue requirement reduction is adjusted to reflect the amounts actually received by the Utility under pending settlements with energy suppliers, including Dynegy.

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 ALJ 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 ALJ'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 November 2004. The PX cannot make its compliance filing until after the ISO makes its filing. 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, after which appellate review is expected. 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. The FERC has indicated that it does not have the power to direct refunds for the period before October 2, 2000, but has engaged in an investigation of market manipulation and sought through settlement or hearings disgorgement of profits for any tariff violations during this period. Unless settled among the various entities, this conclusion will also be subject to judicial review.

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 will reduce the balance of the Settlement Regulatory Asset.

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. Under a bankruptcy court order the aggregate allowable amount of ISO, PX and generator claims was limited to approximately \$1.6 billion. The Utility currently estimates that the claims filed would have been reduced to approximately \$1.2 billion based on the refund methodology recommended in the ALJ'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.

DWR Contracts

The DWR provided approximately 24% of the electricity delivered to the Utility's customers for the three-month period ended March 31, 2004. The DWR purchased the electricity under contracts with various generators. The Utility is responsible for administration and dispatch of the DWR's electricity procurement contracts allocated to the Utility, for purposes of meeting a portion of the Utility's net open position, which is the portion of the demand of a utility's customers, plus applicable reserve margins, not satisfied from that utility's own generation facilities and existing electricity contracts. The DWR remains legally and financially responsible for the electricity procurement contracts.

The 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.

The Utility acts as a billing and collection agent for the DWR's sales of its electricity to retail customers, and as a result, amounts collected on behalf of the DWR (related to its revenue requirement) are excluded from the Utility's revenues. Because of this pass-through nature of amounts collected on behalf of the DWR, and because the Utility is on cost of service ratemaking, changes in the DWR's revenue requirements are not expected to have a material impact on the Utility's results of operations.

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 implied 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 of NEG's creditors prior to NEG's Chapter 11 proceeding, 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 NEG 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 NEG's Board of Directors.

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 NEG or its subsidiaries and approximately \$53 million achieved by the incorporation of certain tax credits related to one of NEG's subsidiaries). In addition to at least \$414 million in damages, the plaintiffs seek punitive damages against PG&E Corporation and the former NEG directors for breach of fiduciary duty and seek punitive damages against PG&E Corporation for deceit as well as interest, costs of suit, and reasonable attorney's fees.

On April 6, 2004, in response to defendants' motion to dismiss many of the plaintiffs' claims, the bankruptcy court entered a memorandum decision, dismissing the following claims: (1) violation of the automatic stay, (2) turnover of property, (3) an accounting, (4) injunctive relief, (5) constructive trust, (6) equitable subordination, and (7) indemnification. The bankruptcy court denied the motion to the extent that it sought dismissal of plaintiffs' claims for breach of fiduciary duty, declaratory judgment, unjust enrichment, fraudulent conveyance, breach of standstill agreement, and deceit. Accepting plaintiffs' allegations as true, as the court is required to do on a motion to dismiss, the bankruptcy court concluded that plaintiffs stated a claim or that factual issues existed with respect to these claims that precluded dismissal at this stage of the proceeding.

Defendants filed a motion in the U.S. District Court of Maryland seeking to transfer the litigation from the bankruptcy court to the District Court. On April 22, 2004, the District Court approved the motion to transfer, and set a trial date for March 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 NEG for the incorporation of losses, deductions or tax credits related to NEG 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. PG&E Corporation anticipates continuing to incorporate losses, deductions and certain tax credits related to NEG or its subsidiaries in PG&E Corporation's consolidated income tax return, until it is no longer consolidated for federal income tax purposes. NEG and its creditors have asserted that NEG 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.

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 \$337 million at March 31, 2004 and approximately \$314 million at December 31, 2003. During the first quarter of 2004, the liability increased by approximately \$23 million mainly due to reassessment of the estimated cost of remediation and remediation payments. The approximately \$337 million accrued at March 31, 2004 includes approximately \$103 million related to the pre-closing remediation liability associated with divested generation facilities and approximately \$234 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 \$337 million environmental remediation liability, approximately \$146 million has been included in prior rate setting proceedings and the Utility expects that approximately \$136 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 \$454 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 \$454 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 will 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 were not discharged in the Utility's Chapter 11 proceeding and have passed 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.

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 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 filed proofs of claim requesting an approximate aggregate amount of \$580 million and approximately another 225 claimants filed claims for an "unknown amount." Pursuant to the Plan of Reorganization, these claims have passed through the Utility's Chapter 11 proceeding unimpaired and will be satisfied by the Utility in the ordinary course of business.

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. On the effective date of the Plan of Reorganization, the automatic stay of pending litigation was lifted, so that any state court lawsuits pending before the Utility's Chapter 11 filing that had not yet received relief from the stay can proceed.

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

To assist in managing and resolving litigation with this many plaintiffs, the parties agreed to select plaintiffs from three of the cases for a test trial. Plaintiffs' counsel selected ten of these initial trial plaintiffs, defense counsel selected seven of the initial trial plaintiffs, and one plaintiff and two alternates were selected at random. The Utility has filed 14 summary judgment motions or motions in limine, which challenge plaintiffs' lack of admissible scientific evidence that chromium caused the injuries alleged by the test plaintiffs. The court began hearing argument on two of the motions in February 2004, but no rulings have been issued. Although the trial date had previously been scheduled to begin in March 2004, the court vacated the trial date and no new trial date has been set.

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 March 31, 2004, the ultimate outcome of this matter will not have a material adverse impact on PG&E Corporation's or the Utility's financial condition or future results of operations.

Recorded Liability for Legal Matters

In accordance with SFAS No. 5, "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 \$191 million (which includes the \$160 million reserve discussed above) at March 31, 2004 and \$205 million at December 31, 2003.

ITEM 2: 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 4.8 million electricity distribution customers and approximately 4.0 million natural gas distribution customers at March 31, 2004. The Utility had approximately \$41.0 billion in assets at March 31, 2004 and generated revenues of approximately \$2.7 billion in the three months ended March 31, 2004. The Utility's revenues are generated mainly through the sale and delivery of electricity and natural gas. The Utility is regulated primarily by the California Public Utilities Commission, or the CPUC, and the Federal Energy Regulatory Commission, or the FERC.

The discussion of the Utility's Chapter 11 proceedings below should be read in conjunction with Note 2 of the Notes to the Consolidated Financial Statements of PG&E Corporation's and the Utility's combined 2003 Annual Report filed with the Current Report on Form 8-K dated March 2, 2004.

Emergence From Chapter 11

On April 12, 2004, the Utility's plan of reorganization, or Plan of Reorganization, under Chapter 11 of the U.S. Bankruptcy Code became effective. The Plan of Reorganization incorporated the terms of the settlement agreement approved by the CPUC on December 18, 2003, and entered into among the CPUC, the Utility and PG&E Corporation on December 19, 2003, to resolve the Utility's Chapter 11 proceeding, or Settlement Agreement. Although the Utility's operations will no longer be subject to the oversight of the bankruptcy court, the bankruptcy court will retain jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Settlement Agreement, (2) the Plan of Reorganization, and (3) the bankruptcy court's December 22, 2003 order confirming the Plan of Reorganization. In addition, the bankruptcy court retains jurisdiction to resolve remaining disputed claims.

In anticipation of its emergence from Chapter 11, the Utility consummated its public offering of \$6.7 billion in first mortgage bonds, or First Mortgage Bonds, on March 23, 2004. Upon the effectiveness of the Plan of Reorganization, the Utility paid all valid claims, deposited funds into escrow accounts for the payment of disputed claims upon resolution, reinstated certain obligations, and paid other obligations. The following table summarizes the sources and uses of funds for these transactions:

(in millions)

Sources		Uses	
First Mortgage Bonds	\$ 6,700	Payments to Creditors	\$ 8,394
Term Loans	799	Disputed Claims Escrow	1,843
Account Receivable Financing Facility	350		
Total Debt Financing	7,849		
Cash used to pay Claims	2,388		

Sources of Funds for Claims	10,237	Uses of Funds for Claims	10,237
Reinstated Pollution Control Bond-Related Obligations	814	Reinstated Pollution Control Bond-Related Obligations	814
Reinstated Preferred Stock	421	Reinstated Preferred Stock	421
Cash on Hand	225	Preferred Dividends	93
		Environmental Measures	10
		Transaction Costs	122
Total Sources of Funds	\$ 11,697	Total Uses of Funds	\$ 11,697

In connection with its emergence from Chapter 11, the Utility received investment grade issuer credit ratings of Baa3 from Moody's Investors Service, or Moody's, and BBB- from Standard & Poor's, or S&P.

Appeals of the bankruptcy court's order confirming the Plan of Reorganization are still pending in the U.S. District Court for the Northern District of California, or the District Court. These appeals were filed by the two CPUC commissioners who did not vote to approve the Settlement Agreement, or the dissenting commissioners, and a municipality. The District Court will set a schedule for briefing and argument of the appeals at a later date. In addition, on April 15, 2004, the City and County of San Francisco, or CCSF, and Aglet Consumer Alliance, or Aglet, each filed a petition with the California Court of Appeal seeking review of the CPUC's December 18, 2003 decision approving the Settlement Agreement and the CPUC's March 16, 2004 decision denying applications for rehearing of its December 18, 2003 decision. CCSF and Aglet allege that the Settlement Agreement violates California law, among other claims. CCSF requests the appellate court to hear and review the CPUC's decisions approving the Settlement Agreement and Aglet requests that the CPUC's decisions be overturned. PG&E Corporation and the Utility believe the petitions are without merit and should be denied. The Utility's answer in opposition to the petitions for review is due May 19, 2004.

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

The Utility believes that the uncertainty regarding the outcome of the pending appeals and petitions does not alter the assessment that the regulatory assets provided under the Settlement Agreement are probable of recovery in rates as discussed below.

Forward-Looking Statements and Risk Factors

This combined Quarterly Report on Form 10-Q, including this MD&A, 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 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 the Implementation of the Utility's Plan of Reorganization Is Disrupted

- The timing and resolution of the petitions for review that were filed in the California Court of Appeal seeking review of the CPUC's December 18, 2003 decision approving the Settlement Agreement and the CPUC's March 16, 2004 denial of applications for rehearing of the December 18, 2003 decision; and
- The timing and resolution of the pending appeals of the bankruptcy court's order confirming 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, the Utility's ability to manage and respond to the levels and volatility successfully, and the extent to which the Utility is able to timely recover increased costs related to such volatility;

- The extent to which the Utility's residual net open position (*i.e.* , that portion of the Utility's electricity customers' demand not satisfied by electricity that the Utility generates or has under contract, or by electricity provided under the California Department of Water Resources, or DWR, electricity contracts allocated to the Utility's customers) increases or decreases due to changes in customer and economic growth rates, the periodic expiration or termination of the Utility's or the DWR's power purchase contracts, the reallocation of the DWR power purchase contracts among the California investor-owned electric utilities, 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, the extent to which the Utility purchases or builds electricity generation facilities, and other factors;
- Weather, storms, earthquakes, fires, floods, other natural disasters, explosions, accidents, mechanical breakdowns and other events or hazards that affect demand, result in power outages, reduce generating output, or cause damage to the Utility's assets or operations or those of third parties on which the Utility relies;
- Unanticipated population growth or decline, changes in market demand and demographic patterns and general economic and financial market conditions, including unanticipated changes in interest or inflation rates, and the extent to which the Utility is able to timely recover its costs in the face of such events;
- The operation of the Utility's Diablo Canyon nuclear power plant, 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 GRC;
- Whether the conditions to securitizing the \$2.21 billion after-tax regulatory asset established under the Settlement Agreement are met, and if so, the timing and amount of the securitization, and the impact such a securitization would have on the Utility's and PG&E Corporation's earnings;
- 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 utilities, self-generation by the Utility's 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.

Financial Summary of the Settlement Agreement

In light of the satisfaction of various conditions to the implementation of the Plan of Reorganization, including the consummation of the public offering of First Mortgage Bonds, the receipt of investment grade credit ratings and final CPUC approval of the Settlement Agreement, the accounting probability standard required to be met under Statement of Financial Accounting Standards, or SFAS, No. 71 in order for the Utility to recognize the regulatory assets provided under the Settlement Agreement (as described below) was met as of March 31, 2004. Therefore, the Utility recorded a \$2.2 billion, after-tax, regulatory asset established under the Settlement Agreement, or Settlement Regulatory Asset, and a \$700 million, after-tax, regulatory asset for the Utility retained generation as summarized in the table below and discussed further in the paragraphs below:

(in millions)	Settlement Regulatory Asset	Utility Retained Generation Regulatory Assets	Total
Authorized, pre-tax, January 1, 2004	\$ 3,730	\$ 1,249	\$ 4,979
Less: amortization from January 1 to March 31	58	21	79
Recognition of regulatory assets, pre-tax, March 31, 2004	3,672	1,228	4,900
Deferred income taxes	1,496	500	1,996
Recognition of regulatory assets, after-tax, March 31, 2004	2,176	728	2,904
Less: offsets of supplier settlements, after tax	8	-	8
Net, March 31, 2004	\$ 2,168	\$ 728	\$ 2,896

Settlement Regulatory Asset - The Settlement Agreement established a \$2.2 billion, after-tax, regulatory asset (which is equivalent to an approximately \$3.7 billion, pre-tax, regulatory asset), as a new, separate and additional part of the Utility's rate base that is being amortized on a "mortgage-style" basis over nine years beginning January 1, 2004. Under this amortization methodology, annual after-tax collections of the Settlement Regulatory Asset are estimated to range from approximately \$140 million in 2004 to approximately \$380 million in 2012. The Settlement Regulatory Asset will be fully amortized by the end of 2012. This after-tax Settlement Regulatory Asset will be reduced for any refunds, claim offsets or other credits the Utility receives from energy suppliers relating to specified electricity procurement costs incurred during the California energy crisis, including those arising from the settlement of CPUC litigation against El Paso Natural Gas Company. As of March 31, 2004, the Utility recognized a one-time non-cash gain of \$3.7 billion, pre-tax, for the Settlement Regulatory Asset.

The unamortized balance of the Settlement 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 the Settlement Regulatory Asset will be no less than 52% for the remaining term. If the Utility completes a refinancing of the Settlement Regulatory Asset supported by a dedicated rate component as discussed below, the equity and debt components of the Utility's rate of return will be replaced with the lower interest rate of the securitized debt.

Utility Retained Generation Regulatory Assets - In the Settlement Agreement, the CPUC deemed the Utility's adopted electricity generation rate base in a 2002 proceeding to be just and reasonable and not subject to modification, adjustment or reduction, except as necessary to reflect capital expenditures and changes in authorized depreciation. Accordingly, as of March 31, 2004, the Utility recognized a one-time non-cash gain of approximately \$1.2 billion, pre-tax, for the retained generation regulatory assets. The individual components of the regulatory assets will be amortized over their respective lives, with a weighted average life of approximately 16 years.

Ratemaking Matters - In the Settlement Agreement, the CPUC agreed to 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 CPUC also agreed to act promptly on certain of the Utility's pending ratemaking proceedings, including the Utility's pending 2003 GRC. The outcome of these proceedings may result in the establishment of additional regulatory assets on the Utility's Consolidated Balance Sheets.

Environmental Measures - In the Settlement Agreement, the Utility agreed to encumber with conservation easements or donate approximately 140,000 acres of land to public agencies or non-profit conservation organizations.

The Utility has established PG&E Environmental Enhancement Corporation as a California non-profit corporation to oversee the environmental enhancements associated with these lands. The Utility has agreed to fund the corporation with \$100 million in cash over ten years, although the Utility will be entitled to recover these payments in rates. At March 31, 2004, the Utility recorded an \$83 million regulatory asset and associated liability based on the discounted present value of future cash payments. On April 12, 2004, the Utility made its first \$10 million installment payment to this corporation.

The Utility has also agreed to establish a California non-profit corporation dedicated to support research and investment in clean energy technology, primarily in the Utility's service territory. The Utility has agreed to fund this corporation with \$30 million payable over five years beginning in January 2005. These contributions may not be recovered in rates. At March 31, 2004, the Utility recorded a \$27 million pre-tax charge to earnings based on the discounted present value of future cash payments.

Of the approximately 140,000 acres referred to above, approximately 44,000 acres may be either donated or encumbered with conservation easements. The remaining land contains the Utility's or a joint licensee's hydroelectric generation facilities and may only be encumbered with conservation easements. At March 31, 2004, the Utility recorded a \$1 million pre-tax charge to earnings associated with the land donation obligation.

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. These amounts will be recovered from customers over a reasonable time of up to four years. At March 31, 2004, the Utility recorded a regulatory asset and associated liability of approximately \$30 million for the CPUC reimbursable fees and expenses. On March 31, 2004, PG&E Corporation recorded the impact of the Settlement Agreement. One of the terms of the Settlement Agreement precluded the Utility from reimbursing PG&E Corporation for certain Chapter 11-related costs. As such, PG&E Corporation reduced its receivable from the Utility, and the Utility reduced its payable to PG&E Corporation, by \$128 million. The transactions were recorded as a contribution to the Utility by PG&E Corporation, net of taxes, and an increase to additional paid-in capital by the Utility.

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 Settlement 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 Settlement 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 Settlement 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. Upon refinancing with securitization, the equity and debt components of the Utility's rate of return on the Settlement 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.

On January 22, 2004, the CPUC approved proposed legislation, Senate Bill 772, which would authorize a dedicated rate component to securitize the Settlement Regulatory Asset and the related taxes. The California legislature has been considering the proposed legislation and it may be presented for signature by the Governor as soon as the end of May 2004.

NEGT

NEGT's Chapter 11 Filing

On July 8, 2003 NEGТ filed a voluntary petition for relief under Chapter 11. The combination of the decline in wholesale electricity prices, the financial commitments related to NEGТ's construction program, the decline of NEGТ's credit rating to below investment grade and the lack of market liquidity created severe financial distress and ultimately caused NEGТ 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. On May 3, 2004, NEGТ's plan of reorganization, which eliminates PG&E Corporation's equity ownership, was confirmed by the bankruptcy court.

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 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 periods are reported as discontinued operations in the Consolidated Statements of Operations. At 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 March 31, 2004 Consolidated Balance Sheets 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 plan of reorganization 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. Upon the effective date of the plan of reorganization, which is anticipated to occur during the second quarter of 2004, PG&E Corporation will record this reversal of its investment in NEGТ and recognize a one-time gain. The effective date is contingent upon certain conditions being met within 90 days following the plan confirmation.

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 implied tax-sharing agreement between PG&E Corporation and NEGТ 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 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 the three-month period ended March 31, 2004 and 2003.

(in millions)	Three Months Ended March 31,	
	2004	2003
Utility		
Electric operating revenue	\$ 1,791	\$ 1,305
Natural gas operating revenue	931	830
Cost of electricity	561	554

Cost of natural gas	578	486
Operating and maintenance	808	712
Recognition of regulatory assets	(4,900)	-
Depreciation, amortization and decommissioning	311	310
Reorganization professional fees and expenses	2	35
Operating income	5,362	38
Interest income	11	11
Interest expense	(213)	(220)
Other expense, net ⁽¹⁾	5	9
Income (loss) before income taxes	5,165	(162)
Income tax benefit (provision)	2,099	(84)
Income (loss) before cumulative effect of a change in accounting principle	3,066	(78)
Cumulative effect of a change in accounting principle	-	(1)
Income (loss) available for (allocated to) common stock	\$ 3,066	\$ (79)
PG&E Corporation, Eliminations and Other ⁽²⁾⁽³⁾		
Operating revenues	\$ -	\$ (2)
Operating expenses	9	(26)
Operating income	(9)	24
Interest income	3	1
Interest expense	(18)	(35)
Other income (expense), net ⁽¹⁾	(32)	(1)
Loss before income taxes	(56)	(11)
Income tax benefit	(23)	(6)
Loss from continuing operations	(33)	(5)
Discontinued operations	-	(265)
Cumulative effect of changes in accounting principles	-	(5)
Net loss	\$ (33)	\$ (275)
Consolidated Total ⁽³⁾		
Operating revenues	\$ 2,722	\$ 2,133
Operating expenses (gain)	(2,631)	2,071
Operating income	5,353	62
Interest income	14	12
Interest expense	(231)	(255)
Other income (expenses), net ⁽¹⁾	(27)	8
Income (loss) before income taxes	5,109	(173)
Income tax provision (benefit)	2,076	(90)
Income (loss) from continuing operations	3,033	(83)
Discontinued operations	-	(265)
Cumulative effect of changes in accounting principles	-	(6)
Net income (loss)	\$ 3,033	\$ (354)

(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 4 of the Notes to the Consolidated Financial Statements.

Utility

Significant Factors Affecting Results

With the implementation of new electricity balancing accounts, electricity procurement costs and items such as changes in sales volumes no longer have the same impact on the Utility's results of operations that they had in prior years. As a result of CPUC decisions approving the Settlement Agreement and implementing various ratemaking mechanisms, the Utility no longer collects the frozen electric rates and surcharges that it collected in 2003, 2002 and 2001. Instead, the Utility collects cost-of-service based electric rates that are the sum of individual revenue requirement components, including base revenue requirements, revenue requirements for the Settlement Regulatory Asset, electricity procurement costs, and the DWR revenue requirement, among others. The GRC 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. The Utility has filed its 2003 GRC with the CPUC and is awaiting a final decision (See the "Regulatory Matters" section of this MD&A).

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 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.

The following presents the Utility's operating results for the first quarters of 2004 and 2003. Net income for the first quarter of 2004 reflects a one-time non-cash gain of approximately \$2.9 billion, after-tax, due to the recognition of regulatory assets provided under the Settlement Agreement.

Electric Operating Revenues

The following table shows a breakdown of the Utility's electric revenue by customer class:

(in millions)	Three Months Ended	
	March 31,	
	2004	2003
Residential	\$ 975	\$ 920
Commercial	866	811
Industrial	267	259
Agricultural	61	68
DWR pass-through revenue	(470)	(757)
Subtotal	1,699	1,301
Miscellaneous	92	4
Total electric operating revenues	\$ 1,791	\$ 1,305

In the first quarter of 2004, the Utility's electricity operating revenues increased approximately \$486 million, or 37%, compared to the same period in 2003 mainly due to the following factors:

- Pass-through revenue to the DWR decreased by approximately \$287 million, or 38%, in the first quarter of 2004 as compared to the first quarter of 2003. This decrease was mainly due to a decrease in the Utility's DWR power charge remittance rate effective January 1, 2004 and a decrease in volume provided by the DWR contracts due to an increase in the amount of electricity generated by the Utility in the first quarter of 2004 as compared to the same period in 2003. The increase in electricity generated by the Utility in 2004 was mainly due to an extended scheduled outage at the Diablo Canyon power plant in the first quarter of 2003.

As previously discussed, with the implementation of cost-of-service based rates, changes in the DWR revenue requirements change rates charged to certain of the Utility's customers. As a result, changes in amounts passed through to the DWR no longer affect the Utility's results of operations as they had in prior years.

- Electric revenue increased by approximately \$305 million as compared to the same period in the prior year due to an electric revenue under-collection in the first quarter of 2003 as a result of the lack of a regulatory recovery mechanism. The implementation of the rate design settlement provides the Utility with a regulatory recovery mechanism in 2004.

- These increases in electric revenues were partially offset by a rate reduction of approximately \$130 million in the first quarter of 2004. The rate design settlement, effective January 1, 2004, implemented an annual electricity rate reduction 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 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:

(in millions)	Three Months Ended March 31,	
	2004	2003
Cost of purchased power	\$ 582	\$ 575
Proceeds from surplus sales allocated to the Utility	(64)	(38)
Fuel used in own generation	43	17
Total cost of electricity	\$ 561	\$ 554
Average cost of purchased power per kWh	\$ 0.083	\$ 0.085
Total purchased power (GWh)	6,997	6,765

In the first quarter of 2004, the Utility's cost of electricity increased approximately \$7 million, or 1%, compared to the same period in 2003 due to an increase in the average cost of fuel used by the Utility's own generation facilities and an increase in the amount of electricity generated by the Utility. The increase in electricity generated by the Utility was mainly due to an extended scheduled refueling outage at the Diablo Canyon power plant in the first quarter of 2003.

The increase in the cost of fuel was partially offset by an increase in surplus sales as the Utility's scheduled power exceeded customer demand in the first quarter of 2004. 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.

Natural Gas Revenues

The following table shows a breakdown of the Utility's natural gas revenues:

(in millions)	Three Months Ended March 31,	
	2004	2003
Bundled gas revenues	\$ 867	\$ 764
Transportation service-only revenues	64	66
Total natural gas revenues	\$ 931	\$ 830
Average bundled revenue per Mcf of natural gas sold	\$ 7.74	\$ 7.28
Total bundled gas sales (in millions of Mcf)	112	105

In the first quarter of 2004, the Utility's total natural gas operating revenues increased approximately \$101 million, or 12%, compared to the same period in 2003 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 the first quarter of 2004 increased \$0.46, or 6%, compared to 2003. In addition, the Utility's total volume of bundled gas sales increased in the first quarter of 2004 by approximately 7% compared to the same period in 2003 mainly due to colder weather.

Cost of Natural Gas

The Utility's cost of natural gas includes the purchase cost of natural gas and transportation costs on interstate and intrastate pipelines. The following table shows a breakdown of the Utility's cost of natural gas:

**Three Months Ended
March 31,**

(in millions)	2004	2003
Cost of natural gas sold	\$ 542	\$ 450
Cost of natural gas transportation	36	36
Total Cost of natural gas	\$ 578	\$ 486
Average cost per Mcf of natural gas purchased	\$ 4.84	\$ 4.29
Total natural gas sold (in millions of Mcf)	112	105

In the first quarter of 2004, the Utility's total cost of natural gas sold increased approximately \$92 million, or 19%, compared to the same period in 2003 mainly due to an increase in the average cost of natural gas sold in 2004 of \$0.55 per Mcf, or 13%. In addition, the Utility's total volume of natural gas sold increased in the first quarter of 2004 by approximately 7% compared to the same period in 2003 mainly due to colder weather.

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, and administrative and general expenses.

In the first quarter of 2004, the Utility's operating and maintenance expenses increased approximately \$96 million, or 13%, compared to the same period in 2003 mainly due to wage increases of approximately \$36 million and higher recorded costs of approximately \$37 million for environmental matters resulting from reassessments of the estimated liability for various sites. In addition, the Utility incurred approximately \$29 million in expenses related to the various provisions of the Settlement Agreement, including obligations to invest in clean energy technology and the donation of land.

Interest Expense

In the first quarter of 2004, the Utility's interest expense decreased approximately \$7 million, or 3%, compared to the same period in 2003 mainly due to a lower average amount of unpaid debts accruing interest.

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. Operating expenses allocated to affiliates are eliminated in consolidation.

In the first quarter of 2004, PG&E Corporation's operating expenses increased by \$35 million. This increase was primarily due to increased external legal fees incurred in relation to the Utility and NEGTC Chapter 11 proceedings and other administrative expenses in 2004.

Interest Expense

PG&E Corporation's interest expense is not allocated to its affiliates. In the first quarter of 2004, PG&E Corporation's interest expense decreased by approximately \$17 million, or 49%, compared to the same period in 2003. The decrease is mainly due to a reduction in principal amounts outstanding and a lower interest rate.

Other Expense

In the first quarter of 2004, PG&E Corporation's other expense increased by \$31 million compared to the same period in 2003. This increase was due to a \$32 million pre-tax charge to earnings related to the change in market value of non-cumulative dividend participation rights included within its \$280 million of 9.50% Convertible Subordinated Notes.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

At March 31, 2004, PG&E Corporation had approximately \$11.3 billion of unrestricted consolidated cash and cash equivalents and restricted cash, of which approximately \$7.8 billion was restricted. PG&E Corporation and the Utility maintain separate bank accounts. At March 31, 2004, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately \$611 million and restricted cash of \$361.5 million. At March 31, 2004 the Utility had cash and cash equivalents and restricted cash of approximately \$10.3 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 March 31, 2004, the Utility had approximately \$2.9 billion of consolidated cash and cash equivalents, and restricted cash of approximately \$7.4 billion. Until March 2004, the Utility's principal source of cash was 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 exceeded its ongoing cash requirements.

During its Chapter 11 proceeding, the Utility did not have access to the capital markets and met all its ongoing cash requirements, including its capital expenditure requirements, with cash generated by its operations. In addition, the Utility paid interest on certain pre-petition liabilities and repaid the principal of maturing mortgage bonds with bankruptcy court approval.

In March 2004, in anticipation of the Utility's emergence from Chapter 11, the Utility and its consolidated subsidiaries issued \$6.7 billion of First Mortgage Bonds and entered into \$2.9 billion of credit facilities. The Utility also obtained an interim \$400 million cash collateralized letter of credit facility, which was terminated on April 12, 2004, the effective date of the Utility's Plan of Reorganization, or the Effective Date, and the letters of credit outstanding were transferred to the Utility's \$850 million working capital facility. Proceeds from the sale of the First Mortgage Bonds, borrowings of approximately \$1.1 billion and approximately \$2.4 billion of cash on hand were used on the Effective Date to pay allowed creditor claims or deposited into escrow to pay disputed claims when resolved. See Note 3 to the Consolidated Financial Statements for further discussion of the First Mortgage Bonds and the Utility's new credit facilities.

The following section discusses the Utility's significant cash flows from operating, investing, and financing activities for the three months ended March 31, 2004 and 2003.

Operating Activities

The Utility's cash flows from operating activities for the three months ended March 31, 2004, and 2003 were as follows:

(in millions)	Three Months Ended March 31,	
	2004	2003
Net income (loss)	\$ 3,074	\$ (73)
Non-cash (income) expenses:		
Depreciation, amortization and decommissioning	311	310
Recognition of regulatory assets, net of tax	(2,904)	-
Change in other working capital	253	24
Other uses of cash:		
Payments authorized by the bankruptcy court on amounts classified as liabilities subject to compromise	(20)	(39)
Other changes in operating assets and liabilities	295	512
Net cash provided by operating activities	\$ 1,009	\$ 734

Net cash provided by operating activities increased by approximately \$275 million during the three months ended March 31, 2004, compared to the same period in 2003 mainly due to the increase in net income for the three months ended March 31, 2004, excluding the one-time non-cash gain, after-tax, of approximately \$2.9 billion related to the recognition of the Settlement Agreement regulatory assets.

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 for the three months ended March 31, 2004. 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 the three months ended March 31, 2004 and 2003 were as follows:

(in millions)	Three Months Ended March 31,	
	2004	2003
Capital expenditures	\$ (342)	\$ (371)

Net proceeds from sale of assets	18	5
Increase in restricted cash	(6,917)	-
Other investing activities	(65)	9
Net cash used by investing activities	\$ (7,306)	\$ (357)

Net cash used by investing activities increased by approximately \$6.9 billion during the three months ended March 31, 2004, compared to the same period in 2003. This increase was mainly due to the following factors:

- Restricted cash increased approximately \$6.9 billion for the three months ended March 31, 2004, compared to the same period in 2003, mainly due to the deposit into an escrow account of the proceeds of the Utility's public offering of approximately \$6.7 billion of First Mortgage Bonds issued in March 2004 and redemption premiums and interest of approximately \$217 million. As the Utility's Plan of Reorganization was not yet effective at the time of closing the offering, the Utility deposited all First Mortgage Bond proceeds into an escrow account. On the Effective Date approximately \$6.9 billion was paid out of the escrow account.
- An increase in nuclear decommissioning funding offset by a decrease in capital expenditures. The decrease in capital expenditures related to a decrease in electricity transmission network expenditures and transmission development project costs offset by an increase in electricity distribution network upgrades during the three months ended March 31, 2004, compared to the same period in 2003.

Financing Activities

Prior to the implementation of the Plan of Reorganization and during its Chapter 11 proceeding, the Utility's financing activities were limited to repayment of secured debt obligations as authorized by the bankruptcy court. During this period, the Utility did not have access to the capital markets. As a result of its emergence from Chapter 11, the Utility has issued significant amounts of debt in connection with the implementation of the Plan of Reorganization and established a working capital facility for the purposes of funding its operating expenses and seasonal fluctuations in working capital and providing letters of credit.

The Utility's cash flows from financing activities for the three months ended March 31, 2004 and 2003 were as follows:

(in millions)	Three Months Ended March 31,	
	2004	2003
Net proceeds from issuance of long-term debt	\$ 6,547	\$ -
Long-term debt issued, matured, redeemed or repurchased	(310)	-
Rate reduction bonds matured	(74)	(74)
Net cash provided (used) by financing activities	\$ 6,163	\$ (74)

For the three months ended March 31, 2004, net cash provided by financing activities increased by approximately \$6.2 billion compared to the same period in 2003. This increase was mainly due to the following factors:

- In March 2004, in connection with the implementation of the Utility's Plan of Reorganization, the Utility consummated a public offering of \$6.7 billion in First Mortgage Bonds. In April 2004, the Utility used the net proceeds of approximately \$6.5 billion from the offering together with other funds to pay creditor claims and deposit funds into escrow for the payment of disputed claims.
- The Utility repaid approximately \$310 million in principal on its first and refunding mortgage bonds that matured in March 2004.

PG&E Corporation

At March 31, 2004, PG&E Corporation's stand-alone cash and cash equivalents balance was approximately \$611 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 during the first quarter of 2004 or 2003. PG&E Corporation also has \$361.5 million of restricted cash that is recorded in noncurrent assets at March 31, 2004. 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 the three months ended March 31, 2004 and 2003. NEGT's tax dispute with PG&E Corporation is discussed above.

PG&E Corporation's consolidated cash flows from operating activities for the three months ended March 31, 2004 and 2003 were as follows:

(in millions)	Three Months Ended March 31,	
	2004	2003
Net income (loss)	\$ 3,033	\$ (354)
Loss from discontinued operations	-	265
Cumulative effect of changes in accounting principles	-	6
Net income (loss) from continuing operations	3,033	(83)
Non-cash (income) expenses:		
Depreciation, amortization and decommissioning	312	310
Recognition of regulatory asset, net of tax	(2,904)	-
Deferred income taxes and tax credits - net	(70)	(15)
Other deferred charges and noncurrent liabilities	237	189
Other changes in operating assets and liabilities	279	532
Net cash provided by operating activities	\$ 887	\$ 933

Net cash provided by operating activities decreased by \$46 million during the three months ended March 31, 2004, compared to the same period in 2003. This decrease was primarily related to decreases in other deferred charges and noncurrent liabilities and restricted cash, partially offset by the Utility's increase in net cash provided from operating activities as discussed above.

Investing Activities

PG&E Corporation, on a stand-alone basis, did not have any material investing activities in the three months ended March 31, 2004 or 2003.

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 the three months ended March 31, 2004 and 2003 were as follows:

(in millions)	Three Months Ended March 31,	
	2004	2003
Net proceeds from long-term debt issued	\$ 6,547	\$ -
Long-term debt matured, redeemed or repurchased	(310)	-
Rate reduction bonds matured	(74)	(74)
Common stock issued	58	21
Net cash provided (used) by financing activities	\$ 6,221	\$ (53)

PG&E Corporation's net cash provided by financing activities increased by \$6.3 billion for the three months ended March 31, 2004, compared to the same period in 2003. This increase was primarily related to the Utility's financing activities as discussed above, in addition to the increase in cash received from the sale of common stock.

Future Liquidity

As a result of its emergence from Chapter 11 on April 12, 2004, 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, the Utility expects to use the amount remaining under its \$850 million working capital facility for the purposes of funding its operating expenses and seasonal fluctuations in working capital and providing letters of credit. At April 12, 2004, approximately \$644 million was available for borrowing under the working capital facility and approximately \$206 million was allocated to outstanding letters of credit. In addition, the

Utility has entered into a \$650 million accounts receivable financing. The Utility used \$350 million on the Effective Date, leaving \$300 million available.

The Utility expects that the cash it retains after its emergence from Chapter 11, together with cash from operating activities and available amounts under the facilities 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 during the Utility's Chapter 11 proceeding. Further, until the 6 7/8% Senior Secured Notes issued by PG&E Corporation are rated Baa3 or better by Moody's and BBB- or better by S&P, PG&E Corporation is prohibited from declaring or paying dividends or repurchasing its common stock. Notwithstanding this restrictive covenant, PG&E Corporation may declare a dividend if certain financial criteria are met or if PG&E Corporation's regular quarterly dividends are funded from proceeds of cash distributions to PG&E Corporation from the Utility. In addition, notwithstanding the restrictive covenant discussed above, PG&E Corporation may repurchase a portion of its common stock if certain financial criteria are met or, with certain restrictions, may repurchase common stock with proceeds of cash distributions to PG&E Corporation from the Utility. PG&E Corporation can redeem the Senior Secured Notes at any time at its option at a premium.

While in Chapter 11, the Utility was prohibited from paying any common or preferred dividends without bankruptcy court approval. Terms of the Settlement Agreement prohibit the Utility from paying any dividends before July 1, 2004. The Utility expects to achieve the target capital structure provided for in the Settlement Agreement by the second half of 2005. Assuming the Utility's target capital structure is met by then, PG&E Corporation aspires to resume paying dividends in the second half of 2005.

CAPITAL EXPENDITURES AND COMMITMENTS

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. In connection with the implementation of the Plan of Reorganization, the Utility issued \$6.7 billion in First Mortgage Bonds, entered into \$2.9 billion in credit facilities, and obtained a \$400 million cash collateralized letter of credit facility. On the Effective Date, the \$400 million letter of credit facility was cancelled and the outstanding letter of credit balance of approximately \$206 million was transferred to the Utility's \$850 million revolving credit facility. In addition, the Utility paid approximately \$8.4 billion in cash to holders of allowed claims and deposited approximately \$1.8 billion into escrow accounts for the payment of disputed claims.

Utility

Power Purchase Agreements

During the first quarter of 2004, the Utility entered into various agreements to purchase energy. Under these agreements, the Utility is committed to make energy payments of approximately \$52 million and capacity payments of approximately \$19 million in 2004.

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 have fluctuated generally based on market conditions.

As a result of the Utility's Chapter 11 filing and its credit rating being below investment grade, the Utility had used several different credit arrangements to purchase natural gas, including a \$10 million cash collateralized standby letter of credit and a pledge of its core natural gas customer accounts receivable. On March 2, 2004, these pledge facilities were replaced with a \$400 million limited cash collateralized letter of credit facility, or gas procurement letter of credit facility. The gas customer accounts receivable program terminated effective March 29, 2004. At March 31, 2004, amounts secured by this gas procurement letter of credit facility totaled approximately \$203 million. Upon emergence from Chapter 11 the Utility canceled this gas procurement letter of credit facility and transferred the outstanding balance to an \$850 million revolving credit facility backed by the Utility's new credit facilities.

At March 31, 2004, the Utility's obligations for natural gas purchases and gas transportation services were as follows:

(in millions)	
2004	\$ 678

2005	168
2006	26
2007	7
2008	-
Thereafter	-
Total	\$ 879

Transmission Control Agreement

The Utility is a party to a Transmission Control Agreement, or TCA, with the California Independent System Operator, or 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 March 31, 2004, the ISO had RMR agreements for which the Utility could be obligated to pay the ISO an estimated \$666 million in net costs during the period April 1, 2004, to March 31, 2006. 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 ALJ 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.

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 generation, procurement and distribution, natural gas distribution and natural gas transportation and storage services in California.

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 costs of transitioning to a competitive market. Although the surcharges implemented in 2001 effectively increased the actual rate under the frozen rate structure, increases in the Utility's authorized costs and 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, effective January 1, 2004, the Utility's rates are intended to reflect cost of service whereby the Utility's rates are based on the sum of individual components. Changes in any individual revenue requirement will change customers' electricity rates.

In February 2004, the CPUC issued a decision approving a rate design settlement to implement an annual electricity rate reduction of approximately \$799 million. Because the Utility's customers' bills did not reflect the rate reduction until March 1, 2004, the Utility will return to customers an estimated \$100 million of revenues received during January and February in excess of those revenues that would have been charged had the rate reduction been implemented on January 1, 2004. The Utility accrued \$100 million at March 31, 2004 for this refund obligation. However, the revised rates approved by the CPUC are based on forecast revenue requirements. Ultimately, rates will be adjusted to collect authorized revenue requirements approved by the CPUC and the FERC in various pending proceedings regardless of the forecast revenue requirements used to set rates approved in February, the refund discussed above, or the rate levels charged. These pending proceedings are discussed below and include:

- The Utility's 2003 GRC and 2004 attrition adjustment request;
- The Utility's cost of capital application;
- Electric transmission rate cases;

- Pending energy supplier refunds, claim offsets or other credits pursuant to the Settlement Agreement;
- The calculation of any over-collection of the surcharge revenues for 2003; and
- The allocation of the DWR's 2004 revenue requirements. Because the Utility is on cost-of-service ratemaking and because amounts collected on behalf of the DWR (related to its revenue requirement) are excluded from the Utility's revenues, changes in the DWR's revenue requirements are not expected to have a material impact on the Utility's results of operations.

2003 General Rate Case

On April 6, 2004, a proposed decision was issued in the Utility's 2003 GRC pending at the CPUC. The 2003 GRC 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 for 2003 and succeeding years. The administrative law judge's, or ALJ's, proposed decision, excluding changes in attrition rate adjustments discussed below, would approve essentially all of the provisions contained in the July 2003 and September 2003 settlement agreements reached among the Utility and various consumer groups to set the Utility's 2003 revenue requirements for its electricity generation and electricity and natural gas distribution operations.

If the proposed decision is adopted by the CPUC, the Utility's total 2003 revenue requirements, as provided in the settlement agreements, would be set at approximately:

- \$2.5 billion for electricity distribution operations, representing a \$236 million increase over the previously authorized amount;
- \$927 million for natural gas distribution operations, representing a \$52 million increase over the previously authorized amount; and
- \$912 million for electricity generation operations, representing a \$38 million increase over the previously authorized amount.

In addition, under the proposed decision, if the Utility forecasts a second refueling outage at the Diablo Canyon nuclear power plant in any one year, the electricity generation revenue requirement would be increased to reflect a fixed revenue requirement of \$32 million per refueling outage, adjusted for changes in the Consumer Price Index, or CPI, in the manner described in the proposed decision. The only forecasted second refueling outage will occur in 2004.

The proposed decision would reject the Utility's request for approximately \$75 million in additional revenue requirements to fund a pension contribution. If adopted, the proposed decision would be retroactive to January 1, 2003.

Because the CPUC has not yet issued a final decision on the Utility's 2003 GRC, the Utility has not included the natural gas distribution revenue requirement increase in its 2003 or 2004 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 \$123 million, which incorporated the impact of the electric portion of the GRC settlement. The Utility has recorded a regulatory liability for the refund obligation. If the 2003 revenue requirement that is ultimately approved in the Utility's 2003 GRC is lower than the amounts described above, the regulatory liability would increase. In 2004, the Utility began recording its base revenue requirements under a cost of service ratemaking structure. In the first quarter of 2004, the Utility collected less than its currently authorized base revenue requirements as approved in its 1999 GRC and 2001 attrition filings. The Utility has recorded the difference between its current base revenue requirement and the amount it has collected through cost of service rates in newly established electricity balancing accounts. The Utility has not included the impact of the electricity distribution revenue requirement increases in its results of operations for the first quarter of 2004. If the CPUC approves a revenue requirement increase in 2004, the Utility would record the increase in the results of operations for 2004.

The proposed decision is scheduled to be considered by the CPUC on May 6, 2004. A final decision is expected in the second quarter of 2004. If the proposed decision is approved as written in the second quarter, the Utility would record regulatory assets and liabilities associated with the revenue requirement increases (including attrition), recovery of unfunded taxes, depreciation, and decommissioning. The net impact of these items is anticipated to result in pre-tax earnings of approximately \$400 million.

Also, on April 6, 2004, the CPUC issued a separate proposed decision to address an agreement between the Utility and the CPUC's Office of Ratepayer Advocates, or ORA, relating to the Utility's response to storm outages and other reliability issues and an agreement the Utility reached with the California Coalition of Utility Employees that proposed a reliability performance incentive mechanism for the Utility beginning in 2004 and continuing through 2009. Among other things, the CPUC accepted the reliability standards proposed by the Utility and

ORA and approved certain reliability improvement initiatives as well as the funding for these initiatives, but rejected the proposed incentive mechanism.

PG&E Corporation and the Utility are unable to predict whether these proposed decisions will be adopted by the CPUC. If the CPUC does not approve the settlement agreements, the Utility's ability to earn its authorized rate of return for the years until the next GRC would be adversely affected. As previously discussed, the rate changes implemented during the first quarter of 2004 contemplated approval for the 2003 GRC consistent with the settlement agreements. To the extent that the final GRC is different from the settlement agreements, rates will be trued-up.

Attrition Rate Adjustments for 2004-2006

The July 2003 and September 2003 settlement agreements in the Utility's 2003 GRC, as discussed above, provide for yearly adjustments to the Utility's base revenues, or attrition rate adjustments. On April 6, 2004, a proposed decision was issued in the Utility's 2003 GRC, pending at the CPUC. The proposed decision would approve the terms of the settlement agreements that provide for an attrition adjustment in 2004, 2005 and 2006 based on changes in the CPI, except the ALJ recommends that the settlement agreements be modified to delete the provision for a minimum attrition adjustment amount in each year.

The proposed minimum attrition adjustments for electricity and natural gas distribution revenue requirements for 2004, 2005 and 2006 are 2.00%, 2.25% and 3.00%, respectively. The proposed minimum attrition adjustments for electricity generation revenue requirements for 2004, 2005 and 2006 are 1.50%, 1.50% and 2.50%, respectively. If the proposed decision is adopted, the aggregate attrition adjustment for 2004 would be approximately \$61 million based on the actual change in the CPI of 1.4%. This would reflect a reduction of approximately \$21 million compared to the Utility's November 2003 and January 2004 combined attrition requests for approximately \$82 million (excluding a \$32 million allowance for a second refueling outage in 2004 at Diablo Canyon nuclear power plant and \$13 million for public purpose program expenses) based on the proposed minimum attrition adjustments in the settlement agreements.

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, natural gas transmission and storage, and electricity generation assets. For its electricity and natural gas distribution operations, natural gas transmission and storage, 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 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%.

The Utility's cost of capital application must be filed by May 12, 2004. In this filing, the Utility plans to propose a true-up cost of capital for 2004 that reflects the Utility's new, post-Chapter 11 financing costs and its updated capital structure. In its application, the Utility will seek recovery in rates of its (1) actual cost of capital from January 1, 2004 through April 11, 2004, (2) its new cost of capital resulting from its Chapter 11 exit financing that became effective on April 12, 2004, and (3) costs associated with interest rate hedges for its Chapter 11 exit financing. For 2004, this cost of capital proceeding will also determine the authorized rate of return for natural gas transportation and storage. For test year 2005, the Utility will request authorization for its cost of common equity, preferred equity and long-term debt and for its capital structure based on forecasts for 2005. The Utility expects that its application will include a forecasted common equity ratio of approximately 49% for 2004.

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' customers. The Utility customers' share of the DWR power charge revenue requirement is approximately \$1.8 billion after consideration of a DWR 2001-2002 adjustment approved in a CPUC decision in January 2004. The January 2004 decision allocated the bond charge revenue requirement among the three California investor-owned electric utilities' customers on an equal cents per kilowatt-hour, or kWh, basis, which resulted in approximately \$369 million being allocated to the Utility's customers. SCE has filed a petition to modify the CPUC's approach for allocating the DWR's bond charges, requesting that more be allocated to the Utility's customers. On April 16, 2004, the assigned ALJ for the proceeding issued a draft decision that would deny SCE's petition. On April 22, 2004, a CPUC commissioner issued an alternate draft decision that would grant SCE's petition on a prospective basis, allocating more of the DWR's bond charges to the Utility. If this alternate draft decision is approved by the CPUC, the bond charges allocated to the Utility's customers would be increased by approximately \$50 million per year for the life of the bonds (through 2020). If approved, however, this is not expected to have an impact on the Utility's results of operations because the Utility is on cost-of-service ratemaking and because amounts collected on behalf of the DWR (related to its revenue requirement) are excluded from the Utility's revenues. The CPUC has not yet acted on this matter.

The CPUC is considering 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. In April 2004, the Utility filed with the CPUC a settlement agreement reached with SCE and TURN on the allocation of the DWR's power charge revenue requirement for 2004 and beyond. The Utility cannot predict the final outcome of this matter.

In April 2004, the DWR submitted the Supplemental Determination of its 2004 revenue requirements to the CPUC for allocation among the three California investor-owned utilities. The Supplemental Determination would reduce the amount of power charge revenues the DWR will recover from electric customers statewide in 2004 by \$245 million. The reduction is primarily driven by higher than projected power charge revenues received by the DWR in 2003, and an increased forecast of revenues from the sale of surplus power in 2004.

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 Proceeding

In May 2002, the CPUC ordered California investor-owned electric utilities to increase baseline allowances for certain residential customers, reducing the Utility's electricity revenues. A customer's baseline allowance is the amount of monthly usage that is billed at the lowest rate and is exempt from certain surcharges. The new balancing account structure approved by the CPUC on April 1, 2004, retroactive to January 1, 2004, provides for full recovery of the Utility's revenue requirements. Therefore, the Utility does not expect that the baseline program revisions will affect the Utility's results of operations.

Electricity Procurement

Effective January 1, 2003, under California law (Assembly Bill 57, or AB 57) 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 forecast 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. At March 31, 2004, the Utility's ERRA had an over-collected balance of \$2.3 million.

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 2004. 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.

In April 2004, the ORA issued its reasonableness review report of the Utility's ERRA covering the period from January 1, 2003 through May 31, 2003. Although the ORA did not specifically recommend any disallowances, the ORA does ask the Utility to provide additional information in future ERRA filings. Additionally, the report indicates that an audit of ERRA entries was not performed but that the ORA intends to perform a full financial audit of the Utility's procurement activities in future ERRA proceedings. The Utility cannot predict whether a disallowance will occur based on information reviewed or audited by the ORA in future ERRA filings or the size of any potential disallowance.

In addition, the CPUC may require the Utility or the Utility may elect to satisfy all or a part of its residual net open position by developing or acquiring additional generation facilities. This could result in significant additional capital expenditures or other costs and may require the Utility to issue additional debt, which the Utility may not be able to issue on reasonable terms, or at all. In addition, if the Utility is not able to recover a material part of the cost of developing or acquiring additional generation facilities in rates in a timely manner, PG&E Corporation's and the Utility's financial condition and results of operations would be materially adversely affected.

Finally, the California Governor has called upon the CPUC to revisit its January 2004 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. Among other requirements, the decision requires the utilities to achieve an electricity reserve margin of 15% to 17% in excess of peak capacity electricity requirements by January 1, 2008. The California Governor has requested that the CPUC accelerate the phase-in of the planning reserve requirement to 2006. The planning reserve requirement will increase the Utility's residual net open position. The Governor also has suggested that the requirement for each California investor-owned electric utility to 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, be amended to reach the 20% goal by 2010 instead.

The Governor's recommendations will be considered by the CPUC in its pending electricity procurement and other proceedings implementing AB 57. The Utility is unable to predict whether the CPUC will adopt the Governor's recommendations, but it is possible that the recommendations if adopted could have a material impact on the Utility's future operations or costs of service.

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 ALJ 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 ALJ'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 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 November 2004. The PX cannot make its compliance filing until after the ISO makes its filing. 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, after which appellate review is expected. 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. The FERC has indicated that it does not have the power to direct refunds for the period before October 2, 2000, but has engaged in an investigation of market manipulation and sought through settlement or hearings disgorgement of profits for any tariff violations during this period. Unless settled among the various entities, this conclusion will also be subject to judicial review.

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 will reduce the balance of the Settlement Regulatory Asset.

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. Under a bankruptcy court order the aggregate allowable amount of ISO, PX and generator claims was limited to approximately \$1.6 billion. The Utility currently estimates that the claims filed would have been reduced to approximately \$1.2 billion based on the refund methodology recommended in the ALJ'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.

El Paso Settlement

In June 2003, the Utility, along with SCE, the state of California and 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 California energy crisis. 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. El Paso also agreed to an approximately \$125 million reduction in El Paso's long-term electricity supply contract with the DWR. 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 net after-tax amount of any consideration that the Utility actually receives in cash related to the electricity refunds will reduce the outstanding balance of the Settlement Regulatory Asset. The settlement was approved by the FERC in November 2003, and by the San Diego Superior Court in December 2003. An appeal of the attorney's fees award to class action plaintiffs' counsel in the litigation is pending, but that appeal will not affect the effectiveness of the settlement. The Superior Court's approval of the settlement is now final and is no longer subject to appeal. The refunds will be released from the escrow account when the settlement becomes effective according to its terms. The Utility believes it is probable that all conditions precedent to the effectiveness of the settlement will be satisfied soon.

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 became effective April 20, 2004. On April 23, 2004, the Utility paid Enron cash of \$309 million, plus interest of approximately \$41 million. These payments have been reflected in the sources and uses of funds table in Note 2 of the Condensed Consolidated Financial Statements. As a result of the Enron Settlement, the Utility will receive an after-tax credit of approximately \$114 million that will reduce the Settlement Regulatory Asset and other regulatory balancing accounts. In the rate design settlement approved by the CPUC on February 26, 2004, the Utility's revenue requirement related to the

amortization of the Settlement Regulatory Asset has been reduced to reflect an estimate of the after-tax credit included in the Enron Settlement. The CPUC decision approving the rate design settlement provides for regulatory balancing account treatment to ensure that the amount of the revenue requirement reduction is adjusted to reflect the net after-tax amounts actually received by the Utility under settlements with energy suppliers, including Enron.

Williams Settlement

On February 24, 2004, the Utility and SCE entered into a settlement agreement with The Williams Companies, or the Williams settlement, settling certain pre-petition claims in the Utility's Chapter 11 proceeding. In order for the settlement to become effective, it must first be approved by the CPUC as to SCE, and the FERC. If the Williams settlement is approved, the Utility will receive an after-tax credit of approximately \$41 million that will reduce the Settlement Regulatory Asset and other regulatory balancing accounts. Certain settlement issues are still being resolved and could impact the amount the Utility ultimately receives. The CPUC decision approving the rate design settlement provides for regulatory balancing account treatment to ensure that the amount of the revenue requirement reduction is adjusted to reflect the amounts actually received by the Utility under pending settlements with energy suppliers, including The Williams Companies.

Dynegy Settlement

In April 2004, the Utility, along with SCE, San Diego Gas and Electric Company, the People of the State of California, and a number of other parties, entered into a settlement agreement with Dynegy Inc., or Dynegy, which resolves alleged overcharge and market manipulation claims from the sale of electricity by Dynegy into the California market during the California energy crisis. In order for this settlement to become effective, it must first be approved by the CPUC and the FERC. If the Dynegy settlement is approved, the Utility estimates it will receive an after-tax credit of approximately \$50 million that will reduce the Settlement Regulatory Asset and other regulatory balancing accounts. The exact amount of the after-tax credit will depend upon the final determination made by the FERC in the pending refund proceeding discussed under "FERC Prospective Price Mitigation Relief" above. The CPUC decision approving the rate design settlement provides for regulatory balancing account treatment to ensure that the amount of the revenue requirement reduction is adjusted to reflect the amounts actually received by the Utility under pending settlements with energy suppliers, including Dynegy.

Natural Gas Supply and Transportation

On March 19, 2004, the Utility filed a gas transportation and storage rate case application. This application proposes a \$435 million revenue requirement for 2005, representing an approximately \$1 million reduction from the 2004 revenue requirement. This application also proposes certain limited rate design changes, as well as eligibility requirements and resulting rates to implement the CPUC's adopted rate structure and fully recover its cost of providing local transmission service.

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.

System Safety and Reliability

Pursuant to California legislation, the Utility was granted base revenue increases for 1997 and 1998 to enhance its transmission and distribution system safety and reliability. In 1999, the Utility filed its application for review and approval of its expenditures related to these enhancements. In March 2004, a proposed decision was issued disallowing approximately \$44.2 million in expenses and \$24.0 million in capital for 1997 and 1998. The proposed decision would also remove storm-related expenses of \$17.2 million and storm-related capital expenditures of \$34.9 million for 1997 and 1998, and would require the Utility to file a new Catastrophic Event Memorandum Account application for recovery of those costs. The Utility filed comments opposing the proposed decision in April 2004. PG&E Corporation and the Utility do not expect that the final outcome of this matter will have a material impact on the Utility's financial position or results of operations.

Electric Restructuring Costs Account Application

On April 16, 2004, the Utility filed an updated Electric Restructuring Costs Account, or ERCA, application for recovery of distribution related electric industry restructuring related revenue requirements totaling \$117 million for the period 1999 through 2002. Revenue requirements associated with these ongoing activities in 2003 and afterwards are included in the 2003 GRC, discussed above. The Settlement Agreement requires timely resolution of this proceeding by the CPUC.

Costs included in this application consist primarily of:

- Expenditures for customer information system and direct access, unbundling, billing and other restructuring activities;
- Other unfunded mandates from the CPUC and the FERC; and

- Costs expended by the Utility that the FERC did not allow the Utility to recover from its wholesale customers.

The Utility has requested that the \$117 million revenue requirement increase become effective January 1, 2005 and be recovered through the Distribution Revenue Adjustment Mechanism, or DRAM.

Because these costs did not meet the applicable accounting probability standard under SFAS No. 71 needed to record regulatory assets, the Utility has not recorded a regulatory asset for the costs it has incurred as of March 31, 2004. PG&E Corporation and the Utility are unable to predict the ultimate outcome of this proceeding.

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 manage the risks associated with ownership of assets, liabilities, committed transactions or probable forecasted transactions, or for complying with and managing risks associated with regulatory programs. 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. 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.

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. In addition, the Utility purchases electricity on the spot market and the short-term forward market (contracts with delivery times ranging from one hour ahead to one year ahead).

It is estimated that the residual net open position (the amount of electricity needed to meet the demands of customers, plus applicable reserve margins, that is not satisfied from the Utility's own generation facilities, purchase contracts or DWR contracts allocated to the Utility's customers) will change over time for a number of reasons, including:

- Periodic expirations of existing electricity purchase contracts, or entering into new electricity purchase contracts;
- Changes in the Utility's customers' electricity demands due to customer and economic growth and weather, and implementation of new energy efficiency and demand response programs, community choice aggregation and a core/noncore retail market structure; and
- Planning reserve and operating requirements.

In addition, unexpected outages at the Utility's generation facilities, or a failure to perform by any of the counterparties to electricity purchase contracts or the DWR allocated contracts, would immediately increase the Utility's residual net open position. The Utility expects to satisfy at least some of the residual net open position through new contracts.

The Settlement Agreement provides that the Utility will recover its reasonable costs of providing utility service, including power procurement costs. In addition, California law requires that the CPUC review revenues and expenses associated with a CPUC-approved procurement plan at least semi-annually through 2006 and adjust retail electricity rates, or order refunds when there is an under- or over-collection exceeding 5% of the Utility's prior year electricity procurement revenues, excluding the revenue collected on behalf of the DWR. In

addition, the CPUC has established a maximum procurement disallowance of approximately \$36 million for the Utility's administration of the DWR contracts and least-cost dispatch. Adverse market price changes are not expected to impact the Utility's net income, while these cost recovery regulatory mechanisms remain in place. However, the Utility is at risk to the extent that the CPUC may in the future disallow transactions 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, these contracts begin to expire in 2004, and prices under new contracts may be higher as a result of such tariffs. In addition, because of an increase in U.S. demand for uranium compared with the domestic supply, uranium prices are trending higher in 2004.

As the Utility replaces existing contracts ending in 2004, new higher priced uranium contracts will raise nuclear fuel costs. The Utility is expected to offset these higher prices with reduced costs for other nuclear fuel components. While the cost recovery mechanisms under California law described above remain in place, adverse market changes in nuclear fuel prices are not expected to impact net income materially.

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 may be purchased in the spot market. 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 Core Procurement Incentive Mechanism, 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 intra state 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 value-at-risk to measure the expected maximum change over a one-day period in the 18-month forward value of its transportation and storage portfolio. This calculation is based on a 95% confidence level, which means that there is a 5% probability that the portfolio will incur a change in value in one day at least as large as the reported value-at-risk. For example, if the value-at-risk is calculated at \$5 million, there is a 95% probability that if prices moved against current positions, the change in the value of the portfolio resulting from a one-day price movement would not exceed \$5 million. The value-at-risk provides an indication of the Utility's exposure to potential market conditions that could impact revenues based on one-day price changes. It is also a way to measure the effectiveness of hedge strategies on a portfolio.

The Utility's value-at-risk for its transportation and storage portfolio was \$3 million at March 31, 2004 and \$4 million at March 31, 2003. A comparison of daily values-at-risk is included in order to provide context around the one-day amounts. The Utility's high, low and average transportation and storage value-at-risk during the first 3 months of 2004 was approximately \$6.4, \$2.9 and \$3.8 million, respectively.

Value-at-risk has several limitations as a measure of portfolio risk, including, but not limited to, underestimation of the risk of a portfolio with significant options exposure, mismatch of one-day liquidation period assumed in the value-at-risk methodology as compared to the longer term holding period of the storage and transportation portfolio, 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 March 31, 2004, if interest rates changed by 1% for all current variable rate debt held by PG&E Corporation and the Utility, the change would affect net income by an immaterial amount, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

The Utility entered into derivative instruments to partially hedge the interest rate risk on up to \$7.4 billion of long-term debt to be issued in conjunction with the emergence from Chapter 11 protection. The cost of the hedges, purchased at fair value, was approximately \$45 million. At March 31, 2004, the hedges were reflected on the balance sheet in other current assets at a fair value of approximately \$0.25 million. On April 13, 2004 the hedges were liquidated for approximately \$1 million. As provided for in the Settlement Agreement with the CPUC, the CPUC agreed that the actual reasonable cost of the interest rate hedging activities with respect to the financing necessary for the Settlement Plan shall be reflected and recoverable in the Utility's retail gas and electric rates without further review. Therefore, the Utility has recorded a regulatory asset for the net costs of the hedges.

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 \$2.1 billion at March 31, 2004 and approximately \$2.5 billion at December 31, 2003. The majority of the accounts receivable were associated with the Utility's residential and small commercial customers. Based upon historical experience and evaluation of then-current factors, allowances for doubtful accounts of approximately \$61 million at March 31, 2004 and approximately \$68 million at December 31, 2003 were recorded against those accounts receivable. In accordance with tariffs, credit risk exposure is limited by requiring deposits from new customers and from those customers whose past payment practices are below standard. The Utility has a regional concentration of credit risk associated with its receivables from residential and small commercial customers in northern and central California. However, material loss due to non-performance from these customers is not considered likely.

The Utility manages credit risk for its wholesale customers and counterparties by assigning credit limits based on an evaluation of their financial condition, net worth, credit rating and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored frequently and a detailed credit analysis is performed at least annually.

Credit exposure for the Utility's wholesale customers and counterparties is calculated daily. If exposure exceeds the established limits, the Utility takes immediate action to reduce the exposure or obtain additional collateral, or both. Further, the Utility relies heavily on master agreements that require security, referred to as credit collateral, in the form of cash, letters of credit, corporate guarantees of acceptable credit quality, or eligible securities if current net receivables and replacement cost exposure exceed contractually specified limits.

The Utility calculates gross credit exposure for each of its wholesale customers and counterparties as the current mark-to-market value of the contract (*i.e.* , the amount that would be lost if the counterparty defaulted today) plus or minus any outstanding net receivables or payables, before the application of credit collateral. During the first three months of 2004, the Utility recognized no material losses due to contract defaults or bankruptcies. At March 31, 2004, there were three counterparties that represented greater than 10% of the Utility's net credit exposure. The Utility had three investment grade counterparties that represented a total of approximately 53% of the Utility's net credit exposure.

The Utility conducts business with wholesale counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. This concentration of counterparties may impact the Utility's overall exposure to credit risk because counterparties may be similarly affected by economic or regulatory changes, or other changes in conditions.

CRITICAL ACCOUNTING POLICIES

The preparation of Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America, or GAAP, involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies, due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ substantially from these estimates. These policies and their key characteristics are outlined below.

Regulatory Assets and Liabilities

PG&E Corporation and the Utility account for the financial effects of regulation in accordance with SFAS No. 71. SFAS No. 71 applies to regulated entities whose rates are designed to recover the cost of providing service. SFAS No. 71 applies to all of the Utility's

operations except for a natural gas pipeline expansion project. During the first quarter of 2004, the Utility began reapplying SFAS No. 71 to its generation operations.

Under SFAS No. 71, regulatory assets represent capitalized costs that otherwise would be charged to expense under GAAP. These costs are later recovered through regulated rates. Regulatory liabilities are created by rate actions of a regulator that will later be credited to customers through the ratemaking process. Regulatory assets and liabilities are recorded when it is probable 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, ALJ proposed decisions, final regulatory orders and the strength or status of applications for regulatory rehearings or state court appeals. The Utility also maintains regulatory balancing accounts, which are comprised of sales and cost balancing accounts. These balancing accounts are used to record the differences between revenues and costs that can be recovered through rates.

If 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 March 31, 2004, PG&E Corporation and the Utility reported regulatory assets (including current regulatory balancing accounts receivable) of approximately \$7.5 billion and regulatory liabilities (including current balancing accounts payable) of approximately \$4.7 billion.

Unbilled Revenues

The Utility records revenue as electricity and natural gas are delivered. A portion of the revenue recognized has not yet been billed. Unbilled revenues are determined by factoring an estimate of the electricity and natural gas load delivered with recent historical usage and rate patterns. As a result of CPUC decisions approving the Settlement Agreement and implementing various ratemaking mechanisms, the Utility no longer records frozen electric rates and surcharges directly to earnings as it had in 2003. Instead, the Utility collects cost-of-service based electric rates that are the sum of specific revenue requirements. As a result, changes in unbilled revenues no longer have the same impact on the Utility's results of operations that they had in prior years.

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 the cost can be estimated in a reasonable manner. The liability can be based on many factors, including site investigations, remediation, operations, maintenance, monitoring and closure. This liability is recorded at the lower range of estimated costs, unless a more objective estimate can be achieved. The recorded liability is re-examined every quarter.

At March 31, 2004, the Utility's accrual for undiscounted environmental liability was approximately \$337 million. The Utility's undiscounted future costs could increase to as much as \$454 million if other potentially responsible parties are not able to contribute to the settlement of these costs or the extent of contamination or necessary remediation is greater than anticipated.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003

In March 2004, the FASB issued Staff Position SFAS No. 106-b, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003," or SFAS No. 106-b. SFAS No. 106-b supersedes 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, and provides guidance on the accounting, disclosure, effective date and transition related to the Prescription Drug Act. Under the current proposal, SFAS No. 106-b is to become effective for the third quarter 2004, which begins on July 1, 2004. PG&E Corporation and the Utility are continuing to evaluate the impact of SFAS 106-b's recognition, measurement and disclosure provisions on their Consolidated Financial Statements.

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 \$75 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit and currently is discussing these adjustments with the IRS' Appeals Office. PG&E Corporation does not expect final resolution of these appeals to have a material impact on PG&E Corporation's financial position or results of operations.

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 NEG'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. One of NEGТ's 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.

Through March 31, 2003, PG&E Corporation increased its valuation allowance against certain state deferred tax assets related to NEGТ or its subsidiaries due to the uncertainty in their realization. Valuation allowances of approximately \$17 million were recorded in discontinued operations, and approximately \$5 million in accumulated other comprehensive loss through March 31, 2003.

PG&E Corporation will not recognize additional income tax benefits for financial reporting purposes after July 7, 2003 with respect to any subsequent losses related to NEGТ or its subsidiaries even though it continues to include NEGТ and its subsidiaries in its consolidated income tax returns. Any such recognized benefits and deferred tax assets arising from losses related to NEGТ 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 NEGТ.

NEGТ and its creditors have brought litigation against PG&E Corporation in NEGТ's Chapter 11 proceeding, asserting that NEGТ is entitled to be compensated under an alleged implied tax sharing agreement between PG&E Corporation and NEGТ 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 tax return. This litigation is discussed above.

ADDITIONAL SECURITY MEASURES

Various federal regulatory agencies have issued guidance and the NRC has issued orders regarding additional security measures to be taken at various facilities, including generation facilities, transmission substations and natural gas transportation facilities. The guidance and the orders require additional capital investment and increased operating costs. However, neither PG&E Corporation nor the Utility believes that these costs will have a material impact on its consolidated financial position or results of operations.

ENVIRONMENTAL AND LEGAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established both to maintain and improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substances, these laws and regulations require PG&E Corporation and the Utility to remove those substances or to remedy effects on the environment. Also, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. See Note 6 of the Notes to the Consolidated Financial Statements for further discussion of environmental matters and significant pending legal matters.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and Pacific Gas and Electric Company's, or the Utility's, primary market risk results from changes in energy prices and interest rates. PG&E Corporation and the Utility engage in price risk management, or PRM, activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these PRM activities using forward contracts, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices, interest rates, and foreign currencies. (See the "Risk Management Activities" section included in Item 2: Management's Discussion and Analysis of Financial Condition and Results of Operations.)

ITEM 4: CONTROLS AND PROCEDURES

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

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

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

For additional information regarding certain of the legal proceedings presented below, see Note 6 of the Notes to the Condensed Consolidated Financial Statements.

Pacific Gas and Electric Company Chapter 11 Filing

Pacific Gas and Electric Company's, or the Utility's, Chapter 11 proceeding has been previously disclosed in PG&E Corporation's and the Utility's combined 2003 Annual Report on Form 10-K in "Part I, Item 3: Legal Proceedings."

As previously disclosed, PG&E Corporation, the Utility and the California Public Utilities Commission, or CPUC, entered into a settlement agreement on December 19, 2003 to resolve the Utility's Chapter 11 proceeding, or the Settlement Agreement. The CPUC had approved the Settlement Agreement on December 18, 2003. On December 22, 2003, the bankruptcy court confirmed the Utility's plan of reorganization, or Plan of Reorganization, that fully incorporated the Settlement Agreement.

On March 16, 2004, the CPUC denied the applications filed by various parties to rehear and reconsider its December 18, 2003 decision approving the Settlement Agreement. In addition, the two CPUC commissioners who did not vote to approve the Settlement Agreement, or the dissenting commissioners, and a municipality 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. The District Court will set a schedule for briefing and argument of the appeals at a later date. On March 26, 2004, the Utility and PG&E Corporation notified the bankruptcy court that all conditions precedent to the effectiveness of the Plan of Reorganization were satisfied. On April 9, 2004, the District Court denied a request filed by the dissenting commissioners to stay the implementation of the Plan of Reorganization on April 12, 2004.

On April 12, 2004, the Utility's Plan of Reorganization became effective. Although the Utility's operations will no longer be subject to the oversight of the bankruptcy court, the bankruptcy court will retain jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Settlement Agreement, (2) the Plan of Reorganization, and (3) the bankruptcy court's confirmation order. The bankruptcy court also will retain jurisdiction to resolve disputed claims. For information regarding the implementation of the Plan of Reorganization, see Note 2 of the Notes to the Condensed Consolidated Financial Statements.

On April 15, 2004, the City and County of San Francisco, or CCSF, and Aglet Consumer Alliance, or Aglet, each filed a petition with the California Court of Appeals seeking review of (1) the CPUC's December 18, 2003 decision approving the Settlement Agreement and (2) the CPUC's March 16, 2004 denial of their applications for rehearing of the CPUC's December 18, 2003 decision. CCSF and Aglet allege that the Settlement Agreement violates California law, among other claims. CCSF requests the appellate court to hear and review the CPUC's decisions approving the Settlement Agreement and Aglet requests that the CPUC's decisions be overturned. PG&E Corporation and the Utility believe the petitions are without merit and should be denied. The Utility's answer in opposition to the petitions for review is due May 19, 2004.

Chapter 11 Filing of NEG T

For information regarding this matter, see PG&E Corporation's and the Utility's combined 2003 Annual Report on Form 10-K, in "Part I, Item 3: Legal Proceedings" and Note 4 of the Notes to the Condensed Consolidated Financial Statements.

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

For more information regarding the Filed Rate Case litigation, see "Part I, Item 3: Legal Proceedings - Pacific Gas and Electric Company vs. Michael Peevey, et al." in PG&E Corporation's and the Utility's combined 2003 Annual Report on Form 10-K.

In re: Natural Gas Royalties Qui Tam Litigation

For information regarding this matter, see "Part I, Item 3: Legal Proceedings" of PG&E Corporation's and the Utility's combined 2003 Annual Report on Form 10-K.

Diablo Canyon Power Plant

As previously disclosed, 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 was 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 had filed a claim in the Utility's Chapter 11 case on behalf of DTSC, and in February 2004 it withdrew those portions of the claim relating to financial assurance and hazardous waste matters.

For more information regarding matters relating to Diablo Canyon Power Plant, see PG&E Corporation's and the Utility's combined 2003 Annual Report on Form 10-K.

Compressor Station Chromium Litigation

As previously disclosed, the Utility has filed 14 summary judgment motions or motions in limine that challenge plaintiffs' lack of admissible scientific evidence that chromium caused the injuries alleged by the test plaintiffs. The Los Angeles Superior Court began hearing argument on two of the motions in February 2004, but no rulings have been issued. Although the trial date had previously been scheduled to begin in March 2004, the Court vacated the trial date, and no new trial date has been set.

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.

For more information regarding the Chromium Litigation, see "Part I, Item 3: Legal Proceedings - Compressor Station Chromium Litigation" in PG&E Corporation's and the Utility's combined 2003 Annual Report on Form 10-K.

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

As previously disclosed in PG&E Corporation's and the Utility's combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, on July 24, 2003, the U.S. District Court for the Northern District of California, or 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, were the property of the Utility's Chapter 11 estate and therefore are properly within the bankruptcy court's jurisdiction. As part of the Utility's Plan of Reorganization, the Utility released PG&E Corporation and the directors from any claims that it might have had for restitution. The Attorney General and the City and County of San Francisco have appealed the District Court's October 2003 ruling to the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit. The defendants filed motions to dismiss the appeals on the ground that the Ninth Circuit lacked jurisdiction to hear them under certain provisions of the U.S. Bankruptcy Code. The Ninth Circuit denied defendants' motions to dismiss in March 2004, and consolidated the two appeals.

The District Court also ruled that the Attorney General's civil penalty and injunctive relief claims under Section 17200 of the California's Business and Professions Code could be resolved in San Francisco Superior Court, where a status conference has been scheduled to occur in July 2004. Under Section 17200, the Attorney General is entitled to seek civil penalties of \$2,500 against each defendant for each violation of Section 17200. The Attorney General's complaint asserted that the total civil penalties would be not less than \$500 million. 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.

For more information regarding these cases, see "Part I, Item 3: Legal Proceedings" of PG&E Corporation's and the Utility's combined 2003 Annual Report on Form 10-K.

ITEM 2. CHANGES IN SECURITIES AND USE OF PROCEEDS

On February 18, 2004, the Board of Directors of PG&E Corporation authorized the amendment of the Rights Agreement, or Rights Agreement, dated as of December 22, 2000, between PG&E Corporation and Mellon Investor Services LLC, or Rights Agent, by providing that the rights to purchase one one-hundredth of a share of PG&E Corporation's Series A Preferred Stock, par value \$100 per share, that were distributed to PG&E Corporation's shareholders on December 20, 2000, will expire on the close of business on the date that Pacific Gas and Electric Company's confirmed plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code becomes effective. PG&E Corporation has delivered to the Rights Agent an Amendment of Rights Agreement and Certification of Compliance with Section 26 dated February 18, 2004, directing the Rights Agent to amend Section 7(a) of the Rights Agreement by deleting clause (ii) thereof and replacing it with the following: "(ii) the Close of Business on the date that Pacific Gas and Electric Company's confirmed plan of reorganization under Chapter 11 of the U.S. Bankruptcy Code becomes effective."

On April 12, 2004, the Utility's Plan of Reorganization became effective and the rights to purchase one one-hundredth of a share of

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

At the time of the Utility's Chapter 11 filing on April 6, 2001, the Utility had defaulted on \$873 million of commercial paper outstanding and had drawn and had outstanding \$938 million under its bank credit facility, which was also in default. As authorized by the bankruptcy court, starting in May 2002, the Utility has made past due and current interest payments on its commercial paper and bank credit facility.

With regard to certain pollution control bond-related debt of the Utility, the Utility had defaulted under the credit agreements with the banks that provide letters of credit as credit and liquidity support for the underlying pollution control bonds. These defaults included the Utility's non-payment of other debt in excess of \$100 million, the Utility's filing of a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code, and non-payment of interest. As a result of these defaults, several of the letters of credit banks caused the acceleration and redemption of four series of pollution control bonds. All of these redemptions were funded by the letters of credit banks. The total principal of the bonds (and related loans) accelerated and redeemed in April and May 2001 was \$454 million. As authorized by the Bankruptcy Court, starting in May 2002, the Utility made past-due and current interest payments on these loans.

In 2002, the Utility paid advances and interest on advances to banks providing letters of credit on pollution control bonds series 96C, 96E, 96F, and 97B. As authorized by the bankruptcy court, starting in June 2002, the Utility also paid past-due interest advances and monthly interest. As authorized by the bankruptcy court, the Utility also made semi-annual interest payments on pollution control bond series 96A backed by bond insurance. With regard to certain pollution control bond-related debt of the Utility backed by the Utility's mortgage bonds, an event of default occurred under the relevant loan agreements with the California Pollution Control Financing Authority due to the Utility's Chapter 11 filing. The Utility obtained bankruptcy court approval to make regular payments on its mortgage bonds and consequently the debt service payments on these bonds were passed through to the pollution control bondholders.

The Utility's filing of a Chapter 11 petition also constituted a default under the indenture that governed its medium-term notes (\$287 million aggregate amount outstanding), five-year 7.375% senior notes (\$680 million aggregate amount outstanding), and floating rate notes (\$1.24 billion aggregate amount outstanding). As authorized by the bankruptcy court, starting in May 2002, the Utility paid past-due and current interest payments on its medium-term notes, its 7.375% senior notes, and its \$1.24 billion floating rate notes. The Utility did not make a principal payment of \$1.24 billion on its 364-day floating rate notes at maturity.

At March 31, 2004, the Utility had not made principal payments on unsecured long-term debt of \$155 million.

With regard to the 7.90% Quarterly Income Preferred Securities, or QUIPS, and the related 7.90% Deferrable Interest Debentures, or Debentures, the Utility's filing of a Chapter 11 petition was an event of default under the applicable indenture. Pursuant to the related trust agreement, the trustee was required to take steps to liquidate the trust and distribute the Debentures to the QUIPS holders. Pursuant to the trustee's notice dated April 24, 2002, the trust was liquidated on May 24, 2002. Upon liquidation of the trust, the former holders of QUIPS received a like amount of 7.90% Deferrable Interest Subordinated Debentures, or QUIDS. As authorized by the bankruptcy court, starting in May 2002, the Utility made past-due and current interest payments on the QUIDS.

The Utility has authorized 75 million shares of First Preferred Stock (\$25 par value) and 10 million shares of \$100 First Preferred Stock (\$100 par value), which may be issued as redeemable or non-redeemable preferred stock. (The Utility has not issued any \$100 First Preferred Stock.) At March 31, 2004, the Utility had issued and outstanding 5,784,825 shares of non-redeemable preferred stock and 5,973,456 shares of redeemable preferred stock. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. The Utility's redeemable preferred stock with mandatory redemption provisions consists of 3 million shares of the 6.57% series and 2.5 million shares of the 6.30% series at March 31, 2004. At the Utility's option, the 6.57% series may be redeemed beginning 2002 and the 6.30% series may be redeemed beginning in 2004 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 stock outstanding. At March 31, 2004, the redemption requirements for the Utility's redeemable preferred stock with mandatory redemption provisions are approximately \$4 million per year for 2002, 2003, and 2004 for the 6.57% series, and \$3 million per year beginning 2004 for the 6.30% series. The Utility is not permitted to make sinking fund payments unless all dividends on preferred stock have been paid. As discussed below, through March 31, 2004, the Utility's Board of Directors did not declare any preferred stock dividends since the dividend paid with respect to the period ended October 31, 2000. Therefore, the \$4 million sinking fund payments that were due on July 31, 2002, and July 31, 2003 to redeem 150,000 shares per sinking fund payment of the 6.57% series were not made. The sinking fund payments are cumulative so that if on July 31 of any given year, the sinking fund payment is not made, the remaining shares of the 6.57% series required to be redeemed must be redeemed before the Utility can issue any shares of another series with a required sinking fund, unless the redemption of shares of both series is pro rata.

Holders of the Utility's non-redeemable 5.0%, 5.5%, and 6.0% series of preferred stock have rights to annual dividends ranging from \$1.25 to \$1.50 per share.

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and equal preference in dividend and liquidation rights. Accumulated and unpaid dividends through March 31, 2004, amounted to \$82.2 million. 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. Until cumulative dividends and cumulative sinking fund payments on its preferred stock are

paid, the Utility may not pay any dividends on its common stock, nor may the Utility repurchase any of its common stock.

Under the Settlement Agreement, the Utility has agreed that it would not pay any dividend on its common stock before July 1, 2004.

On April 12, 2004, the Utility's Plan of Reorganization became effective. In addition to other payments, the Utility paid approximately \$83 million in preferred stock dividends and made sinking fund payments of approximately \$10 million that were in arrears. The Utility's various series of preferred stock remain outstanding. The preferred stock has an aggregate par value of approximately \$421 million, excluding the par value of the shares of 6.57% and 6.30% series of preferred stock that were redeemed on April 12, 2004.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

PG&E Corporation:

On April 21, 2004, PG&E Corporation held its annual meeting of shareholders. At the meeting, the shareholders voted as indicated below on the following matters:

1. Election of the following directors to serve until the next annual meeting of shareholders or until their successors are elected and qualified (included as Item 1 in the proxy statement):

	For	Withheld
David R. Andrews	282,510,885	14,637,181
Leslie S. Biller	286,911,290	10,236,776
David A. Coulter	284,020,634	13,127,432
C. Lee Cox	285,211,839	11,936,227
Robert D. Glynn, Jr.	285,114,172	12,033,894
David M. Lawrence, MD	285,325,514	11,822,552
Mary S. Metz	286,173,133	10,974,933
Barry Lawson Williams	285,712,467	11,435,599

2. Ratification of the appointment of Deloitte & Touche LLP as independent public accountants for 2004 (included as Item 2 in the proxy statement):

For:	289,950,135
Against:	4,308,251
Abstain:	2,889,680

The proposal was approved by a majority of the shares represented and voting (including abstentions) with respect to this proposal, which shares voting affirmatively also constituted a majority of the required quorum.

3. Consideration of a shareholder proposal regarding poison pills (included as Item 3 in the proxy statement):

For:	144,811,801
Against:	80,689,110
Abstain:	4,869,520
Broker non-vote ⁽¹⁾ :	66,777,635

This shareholder proposal was approved by a majority of the shares represented and voting (including abstentions but excluding broker non-votes) with respect to the proposal, which shares voting affirmatively also constituted a majority of the required quorum.

4. Consideration of a shareholder proposal regarding golden parachutes (included as Item 4 in the proxy statement):

For:	104,738,906
Against:	119,653,869

Abstain:	5,977,656
Broker non-vote ⁽¹⁾ :	66,777,635

This shareholder proposal was not approved, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions but excluding broker non-votes) with respect to the proposal.

5. Consideration of a shareholder proposal regarding link-free directors (included as Item 5 in the proxy statement):

For:	34,210,874
Against:	191,266,280
Abstain:	4,893,277
Broker non-vote ⁽¹⁾ :	66,777,635

This shareholder proposal was not approved, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions but excluding broker non-votes) with respect to the proposal.

6. Consideration of a shareholder proposal regarding radioactive wastes (included as Item 6 in the proxy statement):

For:	22,744,297
Against:	188,391,757
Abstain:	19,234,377
Broker non-vote ⁽¹⁾ :	66,777,635

This shareholder proposal was not approved, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions but excluding broker non-votes) with respect to the proposal.

7. Consideration of a shareholder proposal regarding separation of the positions of Chairman of the Board and Chief Executive Officer (included as Item 7 in the proxy statement):

For:	83,424,376
Against:	142,549,868
Abstain:	4,396,187
Broker non-vote ⁽¹⁾ :	66,777,635

This shareholder proposal was not approved, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions but excluding broker non-votes) with respect to the proposal.

8. Consideration of a shareholder proposal regarding executive compensation (included as Item 8 in the proxy statement):

For:	23,405,818
Against:	202,126,494
Abstain:	4,838,119
Broker non-vote ⁽¹⁾ :	66,777,635

This shareholder proposal was not approved, as the number of shares voting affirmatively on the proposal constituted less than a majority of the shares represented and voting (including abstentions but excluding broker non-votes) with respect to the proposal.

⁽¹⁾ A non-vote occurs when a broker or other nominee holding shares for a beneficial owner indicates a vote on one or more proposals, but does not indicate a vote on other proposals because the broker or other nominee does not have discretionary voting power as to such proposals and has not received voting instructions from the beneficial owner as to such proposals.

Pacific Gas and Electric Company:

On April 21, 2004, Pacific Gas and Electric Company (the Utility) held its annual meeting of shareholders. Shares of capital stock of Pacific Gas and Electric Company consist of shares of common stock and shares of first preferred stock. As PG&E Corporation and a subsidiary own all of the outstanding shares of common stock, they hold approximately 95% of the combined voting power of the outstanding capital stock of the Utility. PG&E Corporation and the subsidiary voted all of their respective shares of common stock for the nominees named in the 2004 joint proxy statement and for the ratification of the appointment of Deloitte & Touche LLP as independent public accountants for 2004. The balance of the votes shown below were cast by holders of shares of first preferred stock. At the annual meeting, the shareholders voted as indicated below on the following matters:

1. Election of the following directors to serve until the next annual meeting of shareholders or until their successors are elected and qualified (included as Item 1 in the proxy statement):

	For	Withheld
David R. Andrews	325,831,957	657,306
Leslie S. Biller	326,357,142	132,121
David A. Coulter	326,356,927	132,336
C. Lee Cox	326,358,602	130,661
Robert D. Glynn, Jr.	326,349,700	139,563
David M. Lawrence, MD	326,370,148	119,115
Mary S. Metz	326,355,815	133,448
Gordon R. Smith	326,365,803	123,460
Barry Lawson Williams	326,280,139	209,124

2. Ratification of the appointment of Deloitte & Touche LLP as independent public accountants for 2004 (included as Item 2 in the proxy statement):

For:	326,417,068
Against:	37,181
Abstain:	35,014

The proposal was approved by a majority of the shares represented and voting (including abstentions) with respect to this proposal, which shares voting affirmatively also constituted a majority of the required quorum.

ITEM 5. OTHER INFORMATION

Ratio of Earnings to Fixed Charges and Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends

The Utility's earnings to fixed charges ratio for the three months ended March 31, 2004, was 24.63. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three months ended March 31, 2004, was 22.85. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and exhibits into the Utility's Registration Statement Nos. 33-62488 and 333-10994 relating to various series of the Utility's first preferred stock and its senior secured bonds, respectively.

PG&E Corporation's earnings to fixed charges ratio for the three months ended March 31, 2004, was 20.87. The statement of the foregoing ratio, together with the statement of the computation of the foregoing ratio filed as Exhibits 12.3 hereto, is included herein for the purpose of incorporating such information and exhibit into PG&E Corporation's Registration Statement No. 333-114923 relating to its senior secured notes.

ITEM 6. EXHIBITS AND REPORTS ON FORM 8-K

(a) Exhibits:

- | | |
|-----|--|
| 1.1 | Underwriting Agreement, dated March 18, 2004, between Pacific Gas and Electric Company and Lehman Brothers Inc. and UBS Securities LLC (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004, Exhibit 1.1) |
| 3.1 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed April 12, 2004, Exhibit 3) |
| 3.2 | Bylaws of PG&E Corporation dated as of April 21, 2004 |
| 3.3 | Bylaws of Pacific Gas and Electric Company dated as of April 21, 2004 |
| 4.1 | Amendment of Rights Agreement dated February 18, 2004, between PG&E Corporation and Mellon Investor Services LLC (incorporated by reference to PG&E Corporation and Pacific |

- 4.2 Indenture of Mortgage, dated as of March 11, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004), Exhibit 4.1)
- 4.3 First Supplemental Indenture, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004, Exhibit 4.2)
- 4.4 Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed April 12, 2004, Exhibit 4)
- 4.5 Escrow Deposit and Disbursement Agreement, dated as of March 23, 2004, among Pacific Gas and Electric Company and BNY Western Trust Company as escrow agent and trustee (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004, Exhibit 4.3)
- 4.6 Calculation Agency Agreement, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004, Exhibit 4.4)
- 10.1 Credit Agreement dated as of March 5, 2004 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 10, 2004, Exhibit 99)
- 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
- 12.3 Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
- 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

* 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 first quarter of 2004 and through the date hereof:

- 1. 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

2. February 3, 2004	Item 5. Other Events Implementation of Chapter 11 Settlement Rate Reduction
3. February 19, 2004	Item 5. Other Events and Regulation FD Disclosure 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
4. March 2, 2004	Item 5. Other Events and Regulation FD Disclosure A. Electric Rate Reduction B. Reclassification of Estimated Costs of Removal and Decommissioning Obligations at December 31, 2002. C. Controls and Procedures Item 7. Financial Statements, Pro Forma Financial Information, and Exhibits Exhibit 23 - Independent Auditors' Consent (Deloitte & Touche LLP) Exhibit 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 Exhibit 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 Exhibit 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 (furnished to the SEC) Exhibit 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 (furnished to the SEC) Exhibit 99.1 - This exhibit is comprised of the following portions of the revised 2003 Annual Report to Shareholders of PG&E Corporation and Pacific Gas and Electric Company: "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 Stockholders' 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 Stockholders' Equity," "Notes to Consolidated Financial Statements," and "Quarterly Consolidated Financial Data (Unaudited)" Exhibit 99.2 - Financial Statement Schedules and Independent Auditors' Report (Deloitte & Touche LLP) Exhibit 99.3 - Pacific Gas and Electric Company's Income Statement for the month ended January 31, 2004 and Balance Sheet dated January 31, 2004 (furnished to the SEC) Item 9. Regulation FD Disclosure
5. March 10, 2004	Item 5. Other Events and Regulation FD Disclosure Item 7. Financial Statements, Pro Forma Financial Information, and Exhibits Exhibit 99 - Credit Agreement dated as of March 5, 2004
6. March 12, 2004	Item 5. Other Events and Regulation FD Disclosure A. Rating Agency Actions B. Status Conference Statement
7. March 16, 2004	Item 5. Other Events and Regulation FD Disclosure
8. March 18, 2004	Item 5. Other Events and Regulation FD Disclosure
9. March 23, 2004	Item 5. Other Events and Regulation FD Disclosure Item 7. Financial Statements, Pro Forma Financial Information, and Exhibits

Exhibit 1.1 - Underwriting Agreement, dated March 18, 2004, between Pacific Gas and Electric Company and Lehman Brothers Inc. and UBS Securities LLC (annexes omitted).

Exhibit 4.1 - Indenture of Mortgage, dated as of March 11, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company.

Exhibit 4.2 - First Supplemental Indenture, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company.

Exhibit 4.3 - Escrow Deposit and Disbursement Agreement, dated as of March 23, 2004, among Pacific Gas and Electric Company and BNY Western Trust Company as escrow agent and trustee (Exhibit B omitted).

Exhibit 4.4 - Calculation Agency Agreement, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company.

Exhibit 5.1 - Opinion of Orrick, Herrington & Sutcliffe LLP, dated March 23, 2004, regarding the First Mortgage Bonds.

Exhibit 5.2 - Opinion of Orrick, Herrington & Sutcliffe LLP, dated March 23, 2004, regarding the unsold Senior Secured Bonds.

Exhibit 23.2 - Consent of Orrick, Herrington & Sutcliffe LLP (included as part of their opinions filed herewith).

10. March 26, 2004	Item 5. Other Events and Regulation FD Disclosure
11. March 31, 2004	Item 5. Other Events and Regulation FD Disclosure Item 9. Regulation FD Disclosure - Pacific Gas and Electric Company's Income Statement for the month ended February 29, 2004 and Balance Sheet dated February 29, 2004 (furnished to the SEC)
12. April 7, 2004	Item 5. Other Events and Regulation FD Disclosure A. Pacific Gas and Electric Company's 2003 General Rate Case B. Pacific Gas and Electric Company's Chapter 11 Proceeding
13. April 12, 2004	Item 5. Other Events and Regulation FD Disclosure Pacific Gas and Electric Company's Chapter 11 Proceeding
14. April 12, 2004	Item 5. Other Events and Regulation FD Disclosure Item 7. Financial Statements, Pro Forma Financial Information, and Exhibits Exhibit 3 - Restated Articles of Incorporation of Pacific Gas and Electric Company Exhibit 4 - Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company
15. April 19, 2004	Item 5. Other Events and Regulation FD Disclosure
16. April 27, 2004	Item 5. Other Events and Regulation FD Disclosure Pro forma financial information
17. May 4, 2004	Item 12. Results of Operation and Financial Condition (furnished to the SEC) Release of First Quarter Earnings Results

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this Quarterly Report on Form 10-Q to be signed on their behalf by the undersigned thereunto duly authorized.

PG&E CORPORATION

CHRISTOPHER P. JOHNS
Christopher P. Johns
Senior Vice President and Controller
(duly authorized officer and principal accounting officer)

PACIFIC GAS AND ELECTRIC COMPANY

DINYAR B. MISTRY
Dinyar B. Mistry
Vice President and Controller
(duly authorized officer and principal accounting officer)

Dated: May 4, 2004

EXHIBIT INDEX

- 1.1 Underwriting Agreement, dated March 18, 2004, between Pacific Gas and Electric Company and Lehman Brothers Inc. and UBS Securities LLC (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004, Exhibit 1.1)
- 3.1 Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed April 12, 2004, Exhibit 3)
- 3.2 Bylaws of PG&E Corporation dated as of April 21, 2004
- 3.3 Bylaws of Pacific Gas and Electric Company dated as of April 21, 2004
- 4.1 Amendment of Rights Agreement dated February 18, 2004 between PG&E Corporation and Mellon Investor Services LLC (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed February 19, 2004, Exhibit 99)
- 4.2 Indenture of Mortgage, dated as of March 11, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004, Exhibit 4.1)
- 4.3 First Supplemental Indenture, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004, Exhibit 4.2)
- 4.4 Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed April 12, 2004, Exhibit 4)
- 4.5 Escrow Deposit and Disbursement Agreement, dated as of March 23, 2004, among Pacific Gas and Electric Company and BNY Western Trust Company as escrow agent and trustee (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004, Exhibit 4.3)
- 4.6 Calculation Agency Agreement, dated as of March 23, 2004, between Pacific Gas and Electric Company and BNY Western Trust Company (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 23, 2004, Exhibit 4.4)

10.1	Credit Agreement dated as of March 5, 2004 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 8-K filed March 10, 2004, Exhibit 99)
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
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
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

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

**Bylaws
of
PG&E Corporation
amended as of April 21, 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 eight (8) 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.

Bylaws of Pacific Gas and Electric Company amended as of April 21, 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 nine (9) until changed, within the limits specified above, by an amendment to this Bylaw duly adopted by the Board of Directors or the shareholders.
2. **Powers.** The Board of Directors shall exercise all the powers of the Corporation except those which are by law, or by the Articles of Incorporation of this Corporation, or by the Bylaws conferred upon or reserved to the shareholders.
3. **Committees.** The Board of Directors may, by resolution adopted by a majority of the authorized number of directors, designate and appoint one or more committees as the Board deems appropriate, each consisting of two or more directors, to serve at the pleasure of the Board; provided, however, that, as required by this Corporation's Articles of Incorporation, the members of the Executive Committee (should the Board of Directors designate an Executive Committee) must be appointed by the affirmative vote of two-thirds of the authorized number of directors. Any such committee, including the Executive Committee, shall have the authority to act in the manner and to the extent provided in the resolution of the Board of Directors designating such committee and may have all the authority of the Board of Directors, except with respect to the matters set forth in California Corporations Code Section 311.
4. **Time and Place of Directors' Meetings.** Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, or the President of the Corporation and contained in the notice of any such meeting. Notice of meetings shall be delivered personally or sent by mail or telegram at least seven days in advance.
5. **Special Meetings.** The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate messages, including facsimile, electronic mail, or other such means) to each Director at least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.
6. **Quorum.** A quorum for the transaction of business at any meeting of the Board of Directors or any committee thereof shall consist of one-third of the authorized number of directors or committee members, or two, whichever is larger.
7. **Action by Consent.** Any action required or permitted to be taken by the Board of Directors may be taken without a meeting if all Directors individually or collectively consent in writing to such action. Such written consent or consents shall be filed with the minutes of the proceedings of the Board of Directors.
8. **Meetings by Conference Telephone.** Any meeting, regular or special, of the Board of Directors or of any committee of the Board of Directors, may be held by conference telephone or similar communication equipment, provided that all Directors participating in the meeting can hear one another.

Article III.

OFFICERS.

1. **Officers.** The officers of the Corporation shall be a Chairman of the Board, a Vice Chairman of the Board, a Chairman of the Executive Committee (whenever the Board of Directors in its discretion fills these offices), a President, 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 11
PG&E CORPORATION
COMPUTATION OF EARNINGS (LOSS) PER COMMON SHARE

(in millions, except per share amounts)	Three Months Ended March 31,	
	2004	2003 ⁽¹⁾
Income (loss) from continuing operations	\$ 3,033	\$ (83)
Discontinued operations	-	(265)
Net income (loss) before cumulative effect of changes in accounting principles	3,033	(348)
Cumulative effect of changes in accounting principles	-	(6)
Net income (loss) for basic calculations	3,033	(354)
Earnings (loss) allocated to common shareholders, basic	2,893	(354)
Earnings (loss) allocated to 9.50% Convertible Subordinated Notes, basic	140	-
Net income (loss)	3,033	(354)
9.50% Convertible Subordinated Notes:		
Change in market value of dividend participation rights	19	-
Interest expense	4	-
Net Income (Loss) for diluted calculations	\$ 3,056	\$ (354)
Weighted average common shares outstanding, basic ⁽²⁾	393	382
Add: 9.50 % Convertible Subordinated Notes	19	-
Employee stock options and PG&E Corporation shares held by grantor trusts	7	-
PG&E Corporation Warrants	4	-
Rounding	1	-
Shares outstanding for diluted calculations	424	382
Earnings (Loss) Per Common Share, Basic		
Income (loss) from continuing operations	\$ 7.36	\$ (0.22)
Discontinued operations	-	(0.69)
Cumulative effect of changes in accounting principles	-	(0.02)
Net earnings (loss)	\$ 7.36	\$ (0.93)
Earnings Per Common Share, Diluted		
Income (loss) from continuing operations	\$ 7.21	\$ (0.22)
Discontinued operations	-	(0.69)
Cumulative effect of changes in accounting principles	-	(0.02)
Net earnings (loss)	\$ 7.21	\$ (0.93)

(1) Prior period amounts of NEGTECH, Inc. have been reclassified to discontinued operations.

(2) Weighted average common shares outstanding exclude shares held by a subsidiary of PG&E Corporation (23,815,500 shares at March 31, 2004 and 2003) and PG&E Corporation shares held by grantor trusts to secure deferred compensation obligations (281,985 shares at March 31, 2004 and 2003).

Exhibit 12.1**Pacific Gas and Electric Company****Computation of Ratios of Earnings to Fixed Charges**

(dollars in millions)	Three Months Ended March 31,		Year Ended December 31,			
	2004	2003	2002	2001	2000	1999
Earnings ⁽¹⁾						
Pre-tax income (loss) from continuing operations	\$ 5,173	\$ 1,451	\$ 2,997	\$ 1,611	\$ (5,637)	\$ 1,436
Add:						
Fixed Charges	220	964	1,029	1,019	648	637
Less:						
Preferred dividend requirements of subsidiaries	-	-	-	-	-	-
Total Earnings (Loss)	\$ 5,393	\$ 2,415	\$ 4,026	\$ 2,630	\$ (4,989)	\$ 2,073
Fixed Charges ⁽²⁾						
Interest expense, net, including amortization of debt issue costs, premiums and discounts	\$ 210	\$ 939	\$ 990	\$ 976	\$ 609	\$ 595
AFUDC Debt	5	16	21	12	6	7
Estimate of interest expense within rents	5	9	8	7	9	11
Preferred dividend requirements of subsidiaries	-	-	-	-	-	-
Preferred security requirements of wholly-owned trust	-	-	10	24	24	24
Total Fixed Charges	\$ 220	\$ 964	\$ 1,029	\$ 1,019	\$ 648	\$ 637
Ratio of Earnings (Loss) to Fixed Charges ⁽³⁾	24.51	2.51	3.91	2.58	(7.70)	3.25

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" represents pre-tax income from continuing operations adjusted for minority interest in consolidated subsidiaries and equity in income or loss from subsidiaries accounted for using the equity method plus fixed charges, as computed, less the pre-tax earnings required to cover the preferred dividend requirements of subsidiaries.

(2) "Fixed charges" include interest, including amortization of debt issue costs, premiums and discounts, the debt portion of the allowance for funds used during construction, an estimate of the amount of interest within rents, and the preferred security requirements of consolidated subsidiaries.

(3) The ratio of earnings to fixed charges for the year 2000 indicates a ratio of less than one-to-one. The dollar amount of the deficiency is approximately \$5.6 billion.

Exhibit 12.2**Pacific Gas and Electric Company****Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Dividends**

(dollars in millions)	Three Months Ended March 31,		Year Ended December 31,			
	2004	2003	2002	2001	2000	1999
Earnings ⁽¹⁾						
Pre-tax income (loss) from continuing operations	\$ 5,173	\$ 1,451	\$ 2,997	\$ 1,611	\$ (5,637)	\$ 1,436
Add:						
Fixed Charges	220	964	1,029	1,019	648	637
Less:						
Preferred dividend requirements of subsidiaries	-	-	-	-	-	-
Total Earnings (Loss)	\$ 5,393	\$ 2,415	\$ 4,026	\$ 2,630	\$ (4,989)	\$ 2,073
Fixed Charges ⁽²⁾						
Interest expense, net, including amortization of debt issue costs, premiums and discounts	\$ 210	\$ 939	\$ 990	\$ 976	\$ 609	\$ 595
AFUDC Debt	5	16	21	12	6	7
Estimate of interest expense within rents	5	9	8	7	9	11
Preferred dividend requirements of subsidiaries	-	-	-	-	-	-
Preferred security requirements of wholly-owned trust	-	-	10	24	24	24
Total Fixed Charges	\$ 220	\$ 964	\$ 1,029	\$ 1,019	\$ 648	\$ 637
Preferred Stock Dividends						
Tax deductible dividends	\$ 2	\$ 9	\$ 9	\$ 9	\$ 9	\$ 9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	15	27	28	27	27	27
Total Preferred Stock Dividends	\$ 17	\$ 36	\$ 37	\$ 36	\$ 36	\$ 36
Total Fixed Charges and Preferred Stock Dividends	\$ 237	\$ 1,000	\$ 1,066	\$ 1,055	\$ 684	\$ 673
Ratio of Earnings (Loss) to Combined Fixed Charges and Preferred Stock Dividends ⁽³⁾	22.76	2.42	3.78	2.49	(7.29)	3.08

(1) For purposes of computing the ratio of earnings to fixed charges, "earnings" represents pre-tax income from continuing operations adjusted for minority interest in consolidated subsidiaries and equity in income or loss from subsidiaries accounted for using the equity method plus fixed charges, as computed, less the pre-tax earnings required to cover the preferred dividend requirements of subsidiaries.

(2) "Fixed charges" include interest, including amortization of debt issue costs, premiums and discounts, the debt portion of the allowance for funds used during construction, an estimate of the amount of interest within rents, and the preferred security requirements of consolidated subsidiaries.

(3) The ratio of earnings to fixed charges for the year 2000 indicates a ratio of less than one-to-one. The dollar amount of the deficiency is approximately \$5.6 billion.

Exhibit 12.3
PG&E Corporation
Ratios of Earnings to Fixed Charges

(dollars in millions)	Three Months Ended March 31,		Year Ended December 31,			
	2004	2003	2002	2001	2000	1999
Earnings ⁽¹⁾						
Pre-tax income (loss) from continuing operations	\$ 5,109	\$ 1,249	\$ 2,860	\$ 1,629	\$ (5,543)	\$ 1,368
Add:						
Fixed Charges	256	1,186	1,282	1,141	696	673
Less:						
Pre-tax earnings required to cover preferred dividend requirement of subsidiaries	22	22	25	25	25	25
Earnings	\$ 5,343	\$ 2,413	\$ 4,117	\$ 2,745	\$ (4,872)	\$ 2,016
Fixed Charges ⁽²⁾						
Interest expense, net, including amortization of debt issue costs, premiums and discounts	\$ 228	\$ 1,147	\$ 1,224	\$ 1,078	\$ 639	\$ 615
AFUDC Debt	5	16	21	12	6	7
Estimate of interest expense within rents	1	1	2	2	2	2
Preferred dividend requirements of subsidiaries	22	22	25	25	25	25
Preferred security requirements of wholly-owned trust	-	-	10	24	24	24
Fixed Charges	\$ 256	\$ 1,186	\$ 1,282	\$ 1,141	\$ 696	\$ 673
Ratio of Earnings to Fixed Charges ⁽³⁾	20.9	2.0	3.2	2.4	(7.0)	3.0

- (1) For purposes of computing the ratio of earnings to fixed charges, "earnings" represents pre-tax income from continuing operations adjusted for minority interest in consolidated subsidiaries and equity in income or loss from subsidiaries accounted for using the equity method plus fixed charges, as computed, less the pre-tax earnings required to cover the preferred dividend requirements of subsidiaries.
- (2) "Fixed charges" include interest, including amortization of debt issue costs, premiums and discounts, the debt portion of the allowance for funds used during construction, an estimate of the amount of interest within rents, and the preferred security requirements of consolidated subsidiaries.
- (3) The ratio of earnings to fixed charges for the year 2000 indicates a ratio of less than one-to-one. The dollar amount of the deficiency is approximately \$5.6 billion.

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 report on Form 10-Q for the quarter ended March 31, 2004 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 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: May 4, 2004

ROBERT D. GLYNN, JR.

Robert D. Glynn, Jr.
Chairman, Chief Executive Officer and President
PG&E Corporation

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 report on Form 10-Q for the quarter ended March 31, 2004 of PG&E Corporation;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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 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: May 4, 2004

PETER A. DARBEE

Peter A. Darbee
Senior Vice President and Chief Financial Officer
PG&E Corporation

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 quarterly report on Form 10-Q for the quarter ended March 31, 2004 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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: May 4, 2004

GORDON R. SMITH

Gordon R. Smith
President and Chief Executive Officer
Pacific Gas and Electric Company

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 quarterly report on Form 10-Q for the quarter ended March 31, 2004 of Pacific Gas and Electric Company;
2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;
3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;
4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) 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: May 4, 2004

KENT M. HARVEY

Kent M. Harvey
Senior Vice President - Chief Financial Officer and Treasurer
Pacific Gas and Electric Company

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2004, 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 Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2004, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in such Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2004, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

ROBERT D. GLYNN

ROBERT D. GLYNN, JR.
Chairman, Chief Executive Officer and
President

May 4, 2004

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2004, 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 Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2004, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in such Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2004, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

PETER A. DARBEE

PETER A. DARBEE
Senior Vice President and
Chief Financial Officer

May 4, 2004

**CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2004, I, Gordon R. Smith, President and Chief Executive Officer of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) such Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2004, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in such Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2004, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

GORDON R. SMITH

GORDON R. SMITH

President and Chief Executive Officer

May 4, 2004

**CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO 18 U.S.C. SECTION 1350**

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2004, I, Kent M. Harvey, Senior Vice President, Chief Financial Officer and Treasurer of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) such Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2004, fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
- (2) the information contained in such Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2004, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

KENT M. HARVEY

KENT M. HARVEY

Senior Vice President, Chief Financial Officer
and Treasurer

May 4, 2004

