PG&E CORP

FORM 10-Q
(Quarterly Report)

Filed 08/02/06 for the Period Ending 06/30/06

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

(Mark One)

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended June 30, 2006

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	PG&E Corporation
77 Beale Street	One Market, Spear Tower
P.O. Box 770000	Suite 2400
San Francisco, California 94177	San Francisco, California 94105

Address of principal executive offices, including zip code

Pacific Gas and Electric Company	PG&E Corporation
(415) 973-7000	(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. [X] Yes [ ] No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act.

PG&E Corporation:	[X] Large accelerated filer	[ ] Accelerated Filer	[ ] Non-accelerated filer
Pacific Gas and Electric Company:	[ ] Large accelerated filer	[ ] Accelerated Filer	[X] Non-accelerated filer

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

PG&E Corporation: [ ] Yes [X] No

Pacific Gas and Electric Company:	[ ] Yes	[X] No

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

Common Stock Outstanding as of July 31, 2006:

PG&E Corporation	348,065,769 shares (excluding 24,665,500 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 JUNE 30, 2006
TABLE OF CONTENTS

PART I. FINANCIAL INFORMATION
ITEM 1: CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(in millions, except per share amounts)	(Unaudited) Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Operating Revenues				
Electric	$ 2,214	$ 1,780	$ 4,077	$ 3,439
Natural gas	803	718	2,088	1,727
Total operating revenues	3,017	2,498	6,165	5,166
Operating Expenses				
Cost of electricity	781	487	1,311	884
Cost of natural gas	368	347	1,241	967
Operating and maintenance	982	670	1,844	1,436
Depreciation, amortization and decommissioning	421	454	835	839
Total operating expenses	2,552	1,958	5,231	4,126
Operating Income	465	540	934	1,040
Interest income	41	16	64	37
Interest expense	(164)	(131)	(318)	(292)
Other income (expense), net	28	(2)	28	(3)
Income Before Income Taxes	370	423	708	782
Income tax provision	138	156	262	297
Net Income	$ 232	$ 267	$ 446	$ 485
Weighted Average Common Shares Outstanding, Basic	346	370	345	379
Net Earnings Per Common Share, Basic	$ 0.65	$ 0.70	$ 1.26	$ 1.25
Net Earnings Per Common Share, Diluted	$ 0.65	$ 0.70	$ 1.25	$ 1.23
Dividends Declared Per Common Share	$ 0.33	$ 0.30	$ 0.66	$ 0.60

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	Balance At June 30, 2006 (Unaudited)	Balance At December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 421	$ 713
Restricted cash	1,498	1,546
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $45 million in 2006 and $77 million in 2005)	2,049	2,422
Regulatory balancing accounts	969	727
Inventories:		
Gas stored underground and fuel oil	169	231
Materials and supplies	135	133
Income taxes receivable	100	21
Prepaid expenses and other	262	187
Total current assets	5,603	5,980
Property, Plant and Equipment		
Electric	23,308	22,482
Gas	8,939	8,794
Construction work in progress	718	738
Other	15	16
Total property, plant and equipment	32,980	32,030
Accumulated depreciation	(12,376)	(12,075)
Net property, plant and equipment	20,604	19,955
Other Noncurrent Assets		
Regulatory assets	5,302	5,578
Nuclear decommissioning funds	1,761	1,719
Other	710	842
Total other noncurrent assets	7,773	8,139
TOTAL ASSETS	$ 33,980	$ 34,074

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	Balance At June 30, 2006 (Unaudited)	Balance At December 31, 2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 213	$ 260
Long-term debt, classified as current	282	2
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	346	316
Accounts payable:		
Trade creditors	663	980
Disputed claims and customer refunds	1,720	1,733
Regulatory balancing accounts	1,100	840
Other	452	441
Interest payable	506	473
Deferred income taxes	312	181
Other	1,191	1,416
Total current liabilities	7,075	6,932
Noncurrent Liabilities		
Long-term debt	6,696	6,976
Rate reduction bonds	149	290
Energy recovery bonds	2,116	2,276
Regulatory liabilities	3,487	3,506
Asset retirement obligations	1,633	1,587
Deferred income taxes	3,033	3,092
Deferred tax credits	109	112
Other	1,966	1,833
Total noncurrent liabilities	19,189	19,672
Commitments and Contingencies (Notes 2, 4, 5, 10 and 11)		
Preferred Stock of Subsidiaries	252	252
Preferred Stock		
Preferred stock, no par value, authorized 80,000,000 shares, $100 par value, authorized 5,000,000 shares, none issued	-	-
Common Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, issued 370,937,146 common and 1,353,113 restricted shares in 2006 and 366,868,512 common and 1,399,990 restricted shares in 2005	5,834	5,827
Common stock held by subsidiary, at cost, 24,665,500 shares	(718)	(718)
Unearned compensation	-	(22)
Reinvested earnings	2,356	2,139
Accumulated other comprehensive loss	(8)	(8)
Total common shareholders' equity	7,464	7,218
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 33,980	$ 34,074

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	**(Unaudited) Six Months Ended June 30,**	
	2006	**2005**
Cash Flows From Operating Activities		
Net income	$ 446	$ 485
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	868	839
Deferred income taxes and tax credits, net	69	(115)
Other deferred charges and noncurrent liabilities	155	(75)
Gain on sale of assets	(15)	-
Net effect of changes in operating assets and liabilities:		
Accounts receivable	373	56
Inventories	60	(8)
Accounts payable	(232)	(221)
Accrued taxes	(79)	153
Regulatory balancing accounts, net	18	565
Other current assets	(56)	(35)
Other current liabilities	(103)	(129)
Other	36	68
Net cash provided by operating activities	1,540	1,583
Cash Flows From Investing Activities		
Capital expenditures	(1,178)	(803)
Net proceeds from sale of assets	7	17
Decrease in restricted cash	48	321
Proceeds from nuclear decommissioning trust sales	757	2,008
Purchases of nuclear decommissioning trust investments	(799)	(2,038)
Other	-	42
Net cash used in investing activities	(1,165)	(453)
Cash Flows From Financing Activities		
Borrowings under accounts receivable facility	50	-
Repayments under working capital facility and accounts receivable facility	(310)	(300)
Borrowings under commercial paper facility, net	213	-
Proceeds from issuance of long-term debt, net of issuance costs of $3 million in 2005	-	451
Proceeds from issuance of energy recovery bonds, net of issuance costs of $14 million in 2005	-	1,874
Long-term debt matured, redeemed or repurchased	-	(1,356)
Rate reduction bonds matured	(141)	(141)
Energy recovery bonds matured	(130)	(14)
Preferred stock with mandatory redemption provisions redeemed	-	(122)
Common stock issued	77	190
Common stock repurchased	(114)	(1,065)
Common stock dividends paid	(228)	(111)
Other	(84)	(14)
Net cash used in financing activities	(667)	(608)
Net change in cash and cash equivalents	(292)	522
Cash and cash equivalents at January 1	713	972
Cash and cash equivalents at June 30	$ 421	$ 1,494
Supplemental disclosures of cash flow information		

Cash paid for:		
Interest (net of amounts capitalized)	$ 270	$ 217
Income taxes paid, net	247	241

Supplemental disclosures of noncash investing and financing activities				
Common stock dividends declared but not yet paid	$	115	$	112
Transfer of disputed claims and customer refunds and interest payable to accounts payable - regulatory balancing accounts		-		(378)

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(in millions)	(Unaudited) Three Months Ended June 30, 2006	2005	Six Months Ended June 30, 2006	2005
Operating Revenues				
Electric	$ 2,214	$ 1,780	$ 4,077	$ 3,439
Natural gas	803	718	2,088	1,727
Total operating revenues	3,017	2,498	6,165	5,166
Operating Expenses				
Cost of electricity	781	487	1,311	884
Cost of natural gas	368	347	1,241	967
Operating and maintenance	982	670	1,844	1,441
Depreciation, amortization and decommissioning	421	454	834	839
Total operating expenses	2,552	1,958	5,230	4,131
Operating Income	465	540	935	1,035
Interest income	39	20	58	39
Interest expense	(157)	(124)	(303)	(278)
Other income, net	25	6	31	12
Income Before Income Taxes	372	442	721	808
Income tax provision	141	166	273	309
Net Income	231	276	448	499
Preferred stock dividend requirement	4	4	7	8
Income Available for Common Stock	$ 227	$ 272	$ 441	$ 491

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	Balance At June 30, 2006 (Unaudited)	Balance At December 31, 2005
ASSETS		
Current Assets		
Cash and cash equivalents	$ 165	$ 463
Restricted cash	1,498	1,546
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $45 million in 2006 and $77 million in 2005)	2,049	2,422
Related parties	3	3
Regulatory balancing accounts	969	727
Inventories:		
Gas stored underground and fuel oil	169	231
Materials and supplies	135	133
Income taxes receivable	158	48
Prepaid expenses and other	250	183
Total current assets	5,396	5,756
Property, Plant and Equipment		
Electric	23,308	22,482
Gas	8,939	8,794
Construction work in progress	718	738
Total property, plant and equipment	32,965	32,014
Accumulated depreciation	(12,362)	(12,061)
Net property, plant and equipment	20,603	19,953
Other Noncurrent Assets		
Regulatory assets	5,302	5,578
Nuclear decommissioning funds	1,761	1,719
Related parties receivable	21	23
Other	621	754
Total other noncurrent assets	7,705	8,074
TOTAL ASSETS	$ 33,704	$ 33,783

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	Balance At June 30, 2006 (Unaudited)	Balance At December 31, 2005
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 213	$ 260
Long-term debt, classified as current	2	2
Rate reduction bonds, classified as current	290	290
Energy recovery bonds, classified as current	346	316
Accounts payable:		
Trade creditors	663	980
Disputed claims and customer refunds	1,720	1,733
Related parties	31	37
Regulatory balancing accounts	1,100	840
Other	439	423
Interest payable	506	460
Deferred income taxes	293	161
Other	1,040	1,255
Total current liabilities	6,643	6,757
Noncurrent Liabilities		
Long-term debt	6,696	6,696
Rate reduction bonds	149	290
Energy recovery bonds	2,116	2,276
Regulatory liabilities	3,487	3,506
Asset retirement obligations	1,633	1,587
Deferred income taxes	3,162	3,218
Deferred tax credits	109	112
Other	1,822	1,691
Total noncurrent liabilities	19,174	19,376
Commitments and Contingencies (Notes 2, 4, 5, 10 and 11)		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5.00% to 6.00%, outstanding 5,784,825 shares	145	145
Redeemable, 4.36% to 5.00%, outstanding 4,534,958 shares	113	113
Common stock, $5 par value, authorized 800,000,000 shares, issued 279,624,823 shares	1,398	1,398
Common stock held by subsidiary, at cost, 19,481,213 shares	(475)	(475)
Additional paid-in capital	1,802	1,776
Reinvested earnings	4,913	4,702
Accumulated other comprehensive loss	(9)	(9)
Total shareholders' equity	7,887	7,650
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 33,704	$ 33,783

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited) Six Months Ended June 30, 2006	2005
Cash Flows From Operating Activities		
Net income	$ 448	$ 499
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	867	839
Deferred income taxes and tax credits, net	73	(103)
Other deferred charges and noncurrent liabilities	153	(83)
Gain on sale of assets	(15)	(1)
Net effect of changes in operating assets and liabilities:		
Accounts receivable	373	56
Inventories	60	(8)
Accounts payable	(233)	(222)
Accrued taxes	(110)	188
Regulatory balancing accounts, net	18	565
Other current assets	(52)	(25)
Other current liabilities	(70)	(119)
Other	(2)	18
Net cash provided by operating activities	1,510	1,604
Cash Flows From Investing Activities		
Capital expenditures	(1,178)	(803)
Net proceeds from sale of assets	7	17
Decrease in restricted cash	48	321
Proceeds from nuclear decommissioning trust sales	757	2,008
Purchases of nuclear decommissioning trust investments	(799)	(2,038)
Other	-	42
Net cash used in investing activities	(1,165)	(453)
Cash Flows From Financing Activities		
Borrowings under accounts receivable facility	50	-
Repayments under working capital facility and accounts receivable facility	(310)	(300)
Borrowings under commercial paper facility, net	213	-
Proceeds from issuance of long-term debt, net of issuance costs of $3 million in 2005	-	451
Proceeds from issuance of energy recovery bonds, net of issuance costs of $14 million in 2005	-	1,874
Long-term debt matured, redeemed or repurchased	-	(1,354)
Rate reduction bonds matured	(141)	(141)
Energy recovery bonds matured	(130)	(14)
Common stock dividends paid	(230)	(220)
Preferred stock dividends paid	(7)	(8)
Preferred stock with mandatory redemption provisions redeemed	-	(122)
Common stock repurchased	-	(960)
Other	(88)	-
Net cash used in financing activities	(643)	(794)
Net change in cash and cash equivalents	(298)	357
Cash and cash equivalents at January 1	463	783
Cash and cash equivalents at June 30	$ 165	$ 1,140
Supplemental disclosures of cash flow information		

Cash paid for:

Interest (net of amounts capitalized)	$	243	$	204
Income taxes paid, net		308		237
Supplemental disclosures of noncash investing and financing activities				
Transfer of disputed claims and customer refunds and interest payable to accounts payable - regulatory balancing accounts	$	-	$	(378)

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary purpose is to hold interests in energy-based businesses. The company conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages primarily in the businesses of electricity and natural gas distribution, electricity generation, procurement and transmission, and natural gas procurement, transportation and storage. The Utility is primarily regulated by the California Public Utilities Commission, or CPUC, and the Federal Energy Regulatory Commission, or FERC.

This Quarterly Report on Form 10-Q is a combined report of PG&E Corporation and the Utility. Therefore, the Notes to the unaudited Condensed 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 a variable interest entity which the Utility is required to consolidate under applicable accounting standards. All intercompany transactions have been eliminated from the Condensed Consolidated Financial Statements.

The accompanying interim unaudited Condensed Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America, or GAAP, for interim financial information and in accordance with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X promulgated by the Securities and Exchange Commission, or SEC, and do not contain all of the information and footnotes required by GAAP and the SEC for annual financial statements. The information at December 31, 2005 in both PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets incorporated by reference into their combined Annual Report on Form 10-K for the year ended December 31, 2005. (PG&E Corporation’s and the Utility’s combined Annual Report on Form 10-K for the year ended December 31, 2005, together with the information incorporated by reference into such report, is referred to in this quarterly report as the “2005 Annual Report.”)

Except for the new and significant accounting policies described in Note 2 below, the accounting policies used by PG&E Corporation and the Utility are discussed in Notes 1 and 2 in the Notes to the Consolidated Financial Statements in the 2005 Annual Report.

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 and include, but are not limited to, estimates and assumptions used in determining the Utility's regulatory asset and liability balances based on probability assessments of regulatory recovery, revenues earned but not yet billed (including delayed billings), disputed claims, asset retirement obligations, allowance for doubtful accounts receivable, provisions for losses that are deemed probable from environmental remediation liabilities, pension liabilities, mark-to-market accounting under Statement of Financial Accounting Standards, or SFAS, No. 133, “ Accounting for Derivative Instruments and Hedging Activities, ” as amended, or SFAS No. 133, income tax related liabilities, litigation, and the Utility's review for impairment of long-lived assets and certain identifiable intangibles to be held and used whenever events or changes in circumstances indicate that the carrying amount of its assets might not be recoverable. A change in management's estimates or assumptions could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations during the period in which such change occurred. As these estimates and assumptions involve judgments on a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict, actual results could differ materially from these estimates and assumptions. PG&E Corporation's and the Utility's Condensed Consolidated Financial Statements reflect all adjustments that management believes are necessary for the fair presentation of their financial condition and results of operations for the periods presented. The results of operations for interim periods are not necessarily indicative of the results of operations for the full year.

As discussed below in Note 10, the U.S. Bankruptcy Court for the Northern District of California, or bankruptcy court, which oversaw the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code, or Chapter 11, retains jurisdiction, among other things, to resolve the remaining disputed claims that were made in the Utility's Chapter 11 proceeding.

This quarterly report should be read in conjunction with PG&E Corporation's and the Utility's Consolidated Financial Statements and Notes to the Consolidated Financial Statements in the 2005 Annual Report.

NOTE 2: NEW AND SIGNIFICANT ACCOUNTING POLICIES

Share-Based Payment

On January 1, 2006, PG&E Corporation and the Utility adopted the provisions of SFAS No. 123R, "Share-Based Payment," or SFAS No. 123R, using the modified prospective method which requires that compensation cost be recognized for all share-based payment awards, including unvested stock options, based on the grant-date fair value. SFAS No. 123R requires that an estimate of future forfeitures be made and that compensation cost be recognized only for shares that are expected to vest. Prior to January 1, 2006, PG&E Corporation and the Utility accounted for share-based payments, such as stock options, restricted stock and other share-based incentive awards, under the recognition and measurement provisions of Accounting Principles Board, or APB, Opinion No. 25, "Accounting for Stock Issued to Employees," or Opinion 25, as permitted by SFAS No. 123, "Accounting for Stock-Based Compensation," or SFAS No. 123. Under the provisions of Opinion 25, compensation cost for stock options was not recognized for periods prior to January 1, 2006, as all options granted under those plans had an exercise price equal to the market value of the underlying common stock on the date of grant. The adoption of SFAS No. 123R did not have a material impact on the Condensed Consolidated Financial Statements.

For the three and six months ended June 30, 2006, PG&E Corporation's and the Utility's operating income and income before income taxes are $6 million, $19 million, $4 million and $13 million, respectively, lower than if they had continued to account for share-based payments under Opinion 25. Additionally, for the three and six months ended June 30, 2006, PG&E Corporation's and the Utility's net income are lower by $3 million, $11 million, $2 million and $8 million, respectively, than if they had continued to account for share-based payments under Opinion 25. PG&E Corporation's basic and diluted earnings per common share, or EPS, for the three and six months ended June 30, 2006 would have been $0.66, $1.29, $0.66 and $1.27, respectively, if PG&E Corporation had not adopted SFAS No. 123R. The impact on net income for the three and six months ended June 30, 2006 is primarily attributed to the prospective application of accounting for share-based payment awards with terms that accelerate vesting on retirement and expense recognition of previously unvested stock options.

Prior to the adoption of SFAS No. 123R, PG&E Corporation and the Utility expensed share-based awards over the stated vesting period regardless of terms that accelerate vesting upon retirement. Subsequent to the adoption of SFAS No. 123R, compensation expense for all awards will be recognized over the shorter of the stated vesting period or the requisite service period. If awards granted prior to adopting SFAS No. 123R were expensed over the requisite service period instead of the stated vesting period, there would have been an immaterial impact on the Condensed Consolidated Financial Statements of PG&E Corporation and the Utility for the three and six months ended June 30, 2006.

Prior to the adoption of SFAS No. 123R, PG&E Corporation and the Utility presented all tax benefits from share-based payment awards as operating cash flows in the Statement of Cash Flows. SFAS No. 123R requires the cash flows from the tax benefits resulting from tax deductions in excess of the compensation cost recognized for those awards (excess tax benefits) to be classified as financing cash flows. PG&E Corporation's and the Utility's excess tax benefit of $49 million and $26 million, respectively, would have been classified as an operating cash inflow if PG&E Corporation and the Utility had not adopted SFAS No. 123R (see Note 8 below for further discussion of share-based compensation).

The following table illustrates the effect on PG&E Corporation's net income and EPS for the three and six months ended June 30, 2005 if PG&E Corporation had applied the fair value recognition provisions of SFAS No. 123 to outstanding options.

(in millions, except per share amounts)	**Three Months Ended June 30, 2005**	**Six Months Ended June 30, 2005**
Net income:		
As reported	$ 267	$ 485
Deduct: Incremental share-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(3)	(6)
Pro forma	$ 264	$ 479
Basic earnings per common share:		
As reported	$ 0.70	$ 1.25
Pro forma	0.69	1.23

Diluted earnings per common share:		
As reported	0.70	1.23
Pro forma	0.69	1.22

The following table illustrates the effect on the Utility's net income for the three and six months ended June 30, 2005 if the fair value recognition provisions of SFAS No. 123 had been applied to outstanding options.

(in millions)	**Three Months Ended June 30, 2005**	**Six Months Ended June 30, 2005**
Income available for common stock:		
As reported	$ 272	$ 491
Deduct: Incremental share-based employee compensation expense determined under the fair value based method for all awards, net of related tax effects	(2)	(4)
Pro forma	$ 270	$ 487

Accounting Changes and Error Corrections

On January 1, 2006, PG&E Corporation and the Utility adopted SFAS No. 154, "Accounting Changes and Error Corrections Disclosure," or SFAS No. 154. SFAS No. 154 replaces APB Opinion No. 20, "Accounting Changes" and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." SFAS No. 154 requires retrospective application to prior periods' financial statements of changes in accounting principle unless it is impracticable. SFAS No. 154 applies to all voluntary changes in accounting principle. It also applies to changes required by a new accounting pronouncement unless the new pronouncement includes contrary explicit transition provisions. For example, the retrospective provision of SFAS No. 154 does not apply to the adoption of SFAS No. 123R which includes specific transition provisions that do not require retroactive treatment. The adoption of SFAS No. 154 did not have a material impact on the Condensed Consolidated Financial Statements of PG&E Corporation or the Utility for the three and six months ended June 30, 2006.

Other-Than-Temporary Impairment

In November 2005, the Financial Accounting Standards Board, or FASB, issued Staff Position Nos. FAS 115-1 and 124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments," or FSP 115-1 and 124-1, to provide guidance in determining when an investment is impaired; whether that impairment is other-than-temporary; and the measurement of an impairment loss. PG&E Corporation and the Utility adopted FSP 115-1 and 124-1 on January 1, 2006. The adoption of FSP 115-1 and 124-1 did not have a material impact on the Condensed Consolidated Financial Statements of PG&E Corporation or the Utility for the three and six months ended June 30, 2006.

Changes in Accounting for Certain Derivative Contracts

Derivatives Implementation Group, or DIG, Issue No. B38, "Embedded Derivatives: Evaluation of Net Settlement with respect to the Settlement of a Debt Instrument through Exercise of an Embedded Put Option or Call Option," or DIG B38, and DIG Issue No. B39 "Embedded Derivatives: Application of Paragraph 13(b) to Call Options That Are Exercisable Only by the Debtor," or DIG B39, address the circumstances in which a put or call option embedded in a debt instrument would be bifurcated from the debt instrument and accounted for separately. DIG B38 and DIG B39 were effective from the first quarter of 2006. The adoption of DIG B38 and DIG B39 did not have a material impact on the Condensed Consolidated Financial Statements of PG&E Corporation or the Utility for the three and six months ended June 30, 2006.

Comprehensive Income

For the three and six months ended June 30, 2005, PG&E Corporation's and the Utility's comprehensive income consisted of changes in the effects of the remeasurement of the Utility's defined benefit pension plan. PG&E Corporation and the Utility did not have any comprehensive income activity other than net income for the three and six months ended June 30, 2006.

(in millions)	**PG&E Corporation**	**Utility**

	2006	2005	2006	2005
Three months ended June 30				

Comprehensive income	$ 232	$ 267	$ 227	$ 272
Six months ended June 30				
Net income available for common stock	$ 446	$ 485	$ 441	$ 491
Minimum pension liability adjustment (net of income tax benefit of $2 million in 2005)	-	(1)	-	(2)
Comprehensive income	$ 446	$ 484	$ 441	$ 489

Accumulated Other Comprehensive Income (Loss)

Accumulated other comprehensive income (loss) reports a measure for accumulated changes in equity of PG&E Corporation and the Utility that result 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):

(in millions)	**Hedging Transactions in Accordance with SFAS No. 133**	**Minimum Pension Liability Adjustment**	**Other**	**Accumulated Other Comprehensive Income (Loss)**
Balance at December 31, 2004	$ (1)	$ (4)	$ 1	$ (4)
Period change in:				
Minimum pension liability adjustment	-	(1)	-	(1)
Other	1	-	(1)	-
Balance at June 30, 2005	-	(5)	-	(5)
Balance at December 31, 2005	-	(8)	-	(8)
Balance at June 30, 2006	$ -	$ (8)	$ -	$ (8)

There were no changes in PG&E Corporation's or the Utility's accumulated other comprehensive income (loss) components for the three and six months ended June 30, 2006.

Pension and Other Postretirement Benefits

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan 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 the Utility use a December 31 measurement date for all of their 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.

Net periodic benefit cost as reflected in PG&E Corporation's Condensed Consolidated Statements of Income for the three and six months ended June 30, 2006 and 2005 are as follows:

PG&E Corporation

(in millions)	**Pension Benefits Three Months Ended June 30,**		**Other Benefits Three Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Service cost for benefits earned	$ 59	$ 56	$ 8	$ 9
Interest cost	130	125	19	20
Expected return on plan assets	(157)	(151)	(23)	(21)
Amortization of transition obligation	-	-	6	6

Amortization of prior service cost	14	14	4	3
Amortization of unrecognized loss	8	6	-	-
Net periodic benefit cost	$ 54	$ 50	$ 14	$ 17

(in millions)	Pension Benefits Six Months Ended June 30,		Other Benefits Six Months Ended June 30,	
	2006	**2005**	**2006**	**2005**
Service cost for benefits earned	$ 119	$ 112	$ 17	$ 17
Interest cost	260	249	37	40
Expected return on plan assets	(315)	(301)	(46)	(43)
Amortization of transition obligation	-	-	13	13
Amortization of prior service cost	27	27	8	6
Amortization of unrecognized loss	17	13	(2)	-
Net periodic benefit cost	$ 108	$ 100	$ 27	$ 33

There was no material difference between PG&E Corporation's and the Utility's consolidated net periodic benefit cost.

Under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," as amended, or SFAS No. 71, regulatory adjustments are recorded in the Condensed Consolidated Statements of Income and Condensed 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 purposes, which is based on a funding approach. The CPUC has authorized the Utility to recover the costs associated with its other benefits for 1993 and beyond. Recovery is based on the lesser of the amounts collected in rates or the annual contribution on a tax-deductible basis to the appropriate trusts. For 2006, only the portion of the pension contribution allocated to the Gas Transmission and Storage business is not recoverable in rates. The expected impact to net income for the year ended December 31, 2006 is approximately $5 million.

Nuclear Decommissioning Trust Investment Presentation on Statement of Cash Flows

As reported in the 2005 Annual Report, PG&E Corporation and the Utility changed the presentation of the Nuclear Decommissioning Trust investment in their Consolidated Statements of Cash Flows for the year ended December 31, 2005, to present investing cash outflows separately from investing cash inflows. Cash inflows and outflows in the Nuclear Decommissioning Trust investment balances were previously presented as a single line (net) within the investing section of the Statements of Cash Flows. PG&E Corporation and the Utility have presented cash inflows and outflows for the six months ended June 30, 2006 and 2005 consistent with the 2005 Annual Report presentation. There was no impact to net cash provided by (used in) operating, investing or financing activities as a result of this change in presentation.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Variable Interest Entities

In April 2006, the FASB issued Staff Position No. FIN 46R-6, "Determining the Variability to Be Considered in Applying FASB Interpretation No. 46R," or FSP FIN 46R-6. FSP FIN 46R-6 specifies how a company should determine variability in applying the accounting standard for consolidation of variable interest entities. The pronouncement states that such variability shall be determined based on an analysis of the design of the entity, including the nature of the risks in the entity, the purpose for which the entity was created, and the variability the entity is designed to create and pass along to its interest holders. This new accounting guidance is effective prospectively beginning July 1, 2006, although companies may elect early application and/or retrospective application. PG&E Corporation and the Utility are currently evaluating the impact of this new accounting pronouncement.

Accounting for Uncertainty in Income Taxes

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes" or FIN 48. FIN 48 clarifies the accounting for uncertainty in income taxes. The interpretation prescribes a two-step process in the recognition and measurement of a tax position taken or expected to be taken in a tax return. The first step is to determine if it is more likely than not that a tax position will be sustained upon examination by taxing authorities. If this threshold is met, the second step is to measure the tax position on the balance sheet by using the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also requires additional disclosures. FIN 48 is effective prospectively for fiscal years beginning after December 15, 2006. PG&E Corporation and the Utility are currently evaluating the impact of this new interpretation.

NOTE 3: REGULATORY ASSETS, LIABILITIES AND BALANCING ACCOUNTS

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

Under SFAS No. 71, incurred costs that would otherwise be charged to expense may be capitalized and recorded as regulatory assets if it is probable that the incurred costs will be recovered in rates in the future. The regulatory assets are amortized over future periods consistent with the related increase in customer revenue. If a regulated enterprise is currently recovering through rates, costs that it expects to incur in the future, SFAS No. 71 requires that the regulated enterprise record those expected future costs as regulatory liabilities. Amounts that are probable of being credited or refunded to customers in the future must also be recorded as regulatory liabilities.

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 other reasons, the related regulatory assets and liabilities are written off.

Regulatory Assets

The Utility’s regulatory assets are comprised of the following:

	Balance At	
(in millions)	**June 30, 2006**	**December 31, 2005**
Energy recovery bond regulatory assets	$ 2,354	$ 2,509
Utility retained generation regulatory assets	1,058	1,099
Rate reduction bond regulatory assets	329	456
Regulatory assets for deferred income tax	560	536
Unamortized loss, net of gain on reacquired debt	306	321
Environmental compliance costs	288	310
Regulatory assets associated with plan of reorganization	149	163
Post-transition period contract termination costs	126	131
Other, net	132	53
Total regulatory assets	$ 5,302	$ 5,578

On February 10, 2005 and November 9, 2005, PG&E Energy Recovery Funding LLC, or PERF, a limited liability company wholly owned and consolidated by the Utility (but legally separate from the Utility), issued the first and second series, respectively, of energy recovery bonds, or ERBs. The first series was issued for approximately $1.9 billion to refinance the after-tax balance of the settlement regulatory asset established under the settlement agreement among PG&E Corporation, the Utility, and the CPUC to resolve the Utility’s Chapter 11 proceeding, or the Settlement Agreement. The second series was issued for approximately $844 million to pre-fund the Utility’s tax liability that will be due as the Utility collects the dedicated rate component, or DRC, related to the first series of ERBs. Upon issuance of the first and second series, the Utility recorded ERB regulatory assets of approximately $1.9 billion and $838 million, respectively. For the six months ended June 30, 2006, the Utility recorded amortization of the ERB regulatory assets of approximately $155 million. The Utility expects to fully recover the ERB regulatory assets by the end of 2012.

As a result of the Settlement Agreement, the Utility recognized a one-time non-cash gain of $1.2 billion, pre-tax ($0.7 billion, after-tax), for the Utility retained generation regulatory assets in the first quarter of 2004. The individual components of these regulatory assets will be amortized over their respective lives, with a weighted average life of approximately 16 years. For the six months ended June 30, 2006, the Utility recorded amortization of the Utility’s retained generation regulatory assets of approximately $41 million.

The Utility's regulatory asset related to the rate reduction bonds, or RRBs, represents electric industry restructuring costs that the Utility expects to collect over the term of the RRBs. For the six months ended June 30, 2006, the Utility recorded amortization of the RRB regulatory asset of approximately $127 million. The Utility expects to fully recover the RRB regulatory asset by the end of 2007.

The regulatory assets for deferred income tax represent deferred income tax benefits that have already been passed through to customers and are offset by deferred income tax liabilities. Tax benefits to customers have been passed through as

the CPUC requires utilities under its jurisdiction to follow the “flow through” method of passing certain tax benefits to customers. The “flow through” method ignores the effect of deferred taxes on rates. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover deferred income tax related to regulatory assets over periods ranging from 1 to 40 years.

The regulatory asset related to unamortized loss, net of gain, on reacquired debt represents costs related to debt reacquired or redeemed prior to maturity with associated discount and debt issuance costs. These costs are expected to be recovered over the remaining original amortization period of the reacquired debt over the next 1 to 21 years.

The regulatory asset related to environmental compliance costs represents the portion of estimated environmental remediation liabilities that the Utility expects to recover in future rates as remediation costs are incurred. The Utility expects to recover these costs over periods ranging from 1 to 30 years.

Regulatory assets associated with the Utility’s Chapter 11 plan of reorganization include costs incurred in financing the Utility’s exit from Chapter 11 and costs to oversee the environmental enhancement of the Pacific Forest and Watershed Stewardship Council, an entity that was established pursuant to the Utility’s plan of reorganization. The Utility expects to recover these costs over periods ranging from 5 to 30 years .

Finally, the regulatory asset related to post-transition period contract termination costs represent amounts the Utility incurred in terminating a 30-year power purchase agreement. This regulatory asset will be amortized and collected in rates on a straight-line basis until the end of September 2014, the power purchase agreement’s original termination date.

In general, the Utility does not earn a return on regulatory assets where the related costs do not accrue interest. Accordingly, the only regulatory assets on which the Utility earns a return are the regulatory assets relating to the Utility's retained generation and unamortized loss, net of gain on reacquired debt.

Regulatory Liabilities

The Utility’s regulatory liabilities are comprised of the following:

	Balance At	
(in millions)	**June 30, 2006**	**December 31, 2005**
Cost of removal obligation	$ 2,237	$ 2,141
Asset retirement costs	541	538
Employee benefit plans	216	195
Price risk management	94	213
Public purpose programs	168	154
Rate reduction bonds	129	157
Other	102	108
Total regulatory liabilities	$ 3,487	$ 3,506

The Utility's regulatory liabilities related to the cost of removal obligation represent revenues collected for asset removal costs that the Utility expects to incur in the future. The regulatory liability associated with asset retirement costs represents timing differences between the recognition of asset retirement obligations in accordance with GAAP applicable to non-regulated entities under SFAS No. 143, “Accounting for Asset Retirement Obligations” and FASB Interpretation No. 47, “ Accounting for Conditional Asset Retirement Obligations - an Interpretation of FASB Statement No. 143 ” , or FIN 47, and the amounts recognized for ratemaking purposes. The Utility's regulatory liabilities related to employee benefit plans represent the cumulative differences between expenses recognized in accordance with GAAP and expenses recognized for ratemaking purposes. The Utility’s regulatory liability related to price risk management, or PRM, represents contracts entered into by the Utility to procure electricity and natural gas to reduce commodity price risks, which are accounted for as derivatives under SFAS No. 133. The costs and proceeds of these derivatives are recovered in regulated rates charged to customers. The Utility's regulatory liability related to public purpose programs represents revenues designated for public purpose program costs that are expected to be incurred in the future. The Utility's regulatory liability for RRBs represents the deferral of over-collected revenue associated with the RRBs that the Utility expects to return to customers in the future .

Regulatory Balancing Accounts

The Utility’s regulatory balancing accounts are used as a mechanism for the Utility to recover amounts incurred for certain costs, primarily commodity costs. Sales balancing accounts accumulate differences between revenues and the Utility's authorized revenue requirements. Cost balancing accounts accumulate differences between incurred costs and authorized revenue requirements. The Utility also obtained CPUC approval for balancing account treatment of variances between forecasted and actual commodity costs and volumes. This approval results in eliminating the earnings impact from any throughput and revenue variances from adopted forecast levels. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being credited to customers are recorded as regulatory balancing account liabilities.

The Utility's current regulatory balancing accounts accumulate balances the Utility expects to collect or refund within the next twelve months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next twelve months are included in noncurrent regulatory assets and liabilities. The CPUC does not allow the Utility to offset regulatory balancing account assets against balancing account liabilities.

Current Regulatory Balancing Account Assets

	Balance At	
(in millions)	**June 30, 2006**	**December 31, 2005**
Natural gas revenue and cost balancing accounts	$ 141	$ 159
Electricity revenue and cost balancing accounts	828	568
Total	$ 969	$ 727

Current Regulatory Balancing Account Liabilities

	Balance At	
(in millions)	**June 30, 2006**	**December 31, 2005**
Natural gas revenue and cost balancing accounts	$ 156	$ 13
Electricity revenue and cost balancing accounts	944	827
Total	$ 1,100	$ 840

During the six months ended June 30, 2006, the under-collection in the Utility’s electricity revenue and cost balancing account assets increased as customers’ usage generated revenues less than the electricity revenue requirements, which are recorded on a straight-line basis throughout the year. This is anticipated during the winter and spring when electricity usage is lower as compared to the warmer summer months. The over-collection in the Utility’s electricity revenue and cost balancing account liabilities increased primarily as a result of an exceptionally wet winter that allowed the Utility to procure electricity from its hydroelectric resources rather than through the higher-cost power from qualifying facilities, or QFs. In addition, the Utility reflected the benefit of settlements with energy suppliers in its electricity revenue and cost balancing account liabilities, further increasing the over-collection.

The over-collection recorded in the Utility’s natural gas revenue and cost balancing account liabilities was primarily a result of revenue requirements, which are recorded on a straight-line basis throughout the year, exceeding the Utility’s revenues during the spring when gas usage declines as the weather becomes warmer.

NOTE 4: DEBT

PG&E Corporation

For details on PG&E Corporation’s and the Utility’s debt obligations, credit facilities and short-term borrowings not discussed below, refer to Note 4 in the Notes to the Consolidated Financial Statements in the 2005 Annual Report.

Convertible Subordinated Notes

PG&E Corporation currently has outstanding $280 million of 9.50% Convertible Subordinated Notes, or Convertible Subordinated Notes, that are scheduled to mature on June 30, 2010. These Convertible Subordinated Notes may be converted (at the option of the holder) at any time prior to maturity into 18,558,655 shares of common stock of PG&E Corporation, at a conversion price of approximately $15.09 per share. The conversion price is subject to an adjustment should a significant change occur in the number of PG&E Corporation's outstanding common shares. To date, the conversion price has not required adjustment. In addition, holders of the Convertible Subordinated Notes are entitled to receive “pass

-through dividends" determined by multiplying the amount of the cash dividend paid by PG&E Corporation per share of common stock by a number equal to the principal amount of the Convertible Subordinated Notes divided by the conversion price. In connection with each of the common stock dividends paid on January 17, April 17, and July 17, 2006, PG&E Corporation paid approximately $6 million of " pass-through dividends " to the holders of Convertible Subordinated Notes . The holders have a one-time right to require PG&E Corporation to repurchase the Convertible Subordinated Notes on June 30, 2007, at a purchase price equal to the principal amount plus accrued and unpaid interest (including liquidated damages and unpaid "pass-through dividends," if any). Accordingly, PG&E Corporation has classified the Convertible Subordinated Notes in Current Liabilities - Long-term debt, classified as current in the accompanying Condensed Consolidated Balance Sheet as of June 30, 2006.

In accordance with SFAS No. 133, the dividend participation rights component is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Condensed Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Condensed Consolidated Statements of Income as a non-operating expense or income (included in Other income (expense), net). At June 30, 2006 and December 31, 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $86 million and $92 million, respectively, of which $23 million and $22 million, respectively, was classified as a current liability (in Current Liabilities - Other) and $63 million and $70 million, respectively, was classified as a noncurrent liability (in Noncurrent Liabilities - Other).

Utility

Pollution Control Bonds

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank issued various series of tax-exempt pollution control bonds for the benefit of the Utility. At June 30, 2006, pollution control bonds in the aggregate principal amount of $1.6 billion were outstanding. Under the pollution control bond loan agreements, the Utility is obligated to pay on the due dates an amount equal to the principal, premium (if any) and interest on these bonds to the trustees for the bonds.

All of the pollution control bonds financed or refinanced pollution control facilities at the Utility's Geysers geothermal power plant, or the Geysers Project, or at the Utility's Diablo Canyon nuclear power plant, or Diablo Canyon. In 1999, the Utility sold the Geysers Project to Geysers Power Company LLC, a subsidiary of Calpine Corporation. The Geysers Project purchase and sale agreements state that Geysers Power Company LLC will use the facilities solely as pollution control facilities within the meaning of Section 103(b)(4)(F) of the Internal Revenue Code and associated regulations, or the Code. On February 3, 2006, Geysers Power Company LLC filed for reorganization under Chapter 11. The Utility believes that the Geysers Project will continue to meet the use requirements of the Code.

Commercial Paper Program

On January 10, 2006, the Utility entered into various agreements to establish the terms and procedures for the issuance of up to $1 billion of unsecured commercial paper by the Utility for general corporate purposes. The commercial paper will not be registered under the Securities Act of 1933 or applicable state securities laws and may not be offered or sold in the United States absent registration under the Securities Act of 1933 or applicable state securities laws or an applicable exemption from registration requirements. The commercial paper may have maturities of up to 365 days and will rank equally with the Utility's unsubordinated and unsecured indebtedness. At June 30, 2006, the Utility had $213 million of commercial paper outstanding at an average rate of approximately 5.46%. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance.

Rate Reduction Bonds

In December 1997, PG&E Funding LLC, a limited liability corporation wholly owned by and consolidated by the Utility, issued $2.9 billion of RRBs. The proceeds of the RRBs were used by PG&E Funding LLC to purchase from the Utility the right, known as " transition property, " to be paid a specified amount from a charge levied on residential and small commercial customers. The total principal amount of RRBs outstanding at June 30, 2006 was approximately $439 million.

While PG&E Funding LLC is a wholly owned consolidated subsidiary of the Utility, it is legally separate from the Utility. The assets of PG&E Funding LLC are not available to creditors of the Utility or PG&E Corporation, and the transition property is not legally an asset of the Utility or PG&E Corporation. The RRBs are secured solely by the transition property and there is no recourse to the Utility or PG&E Corporation.

Energy Recovery Bonds

In 2005, PERF issued two separate series of ERBs in the aggregate amount of $2.7 billion. The proceeds of the ERBs were used by PERF to purchase from the Utility the right, known as " recovery property, " to be paid a specified amount from a DRC. DRC charges are authorized by the CPUC under state legislation and will be paid by the Utility's electricity customers until the ERBs are fully retired. The total principal amount of ERBs outstanding at June 30, 2006 was approximately $2.5 billion.

While PERF is a wholly owned consolidated subsidiary of the Utility, PERF is legally separate from the Utility. The assets of PERF (including the recovery property) are not available to creditors of the Utility or PG&E Corporation and the recovery property is not legally an asset of the Utility or PG&E Corporation.

NOTE 5: SHAREHOLDERS' EQUITY

PG&E Corporation's and the Utility's changes in shareholders' equity for the six months ended June 30, 2006 were as follows:

	PG&E Corporation	Utility
(in millions)	**Total Common Shareholders' Equity**	**Total Shareholders' Equity**
Balance at December 31, 2005	$ 7,218	$ 7,650
Net income	446	448
Common stock issued	83	-
PG&E Corporation common stock repurchased:		
Settlement of accelerated share repurchase obligation - March 2006	(58)	-
Settlement of accelerated share repurchase obligation - June 2006	(56)	-
Common restricted stock amortization	11	-
Common stock dividends paid	(114)	(230)
Common stock dividends declared but not yet paid	(115)	-
Preferred stock dividends	-	(7)
Tax benefit from share-based payment awards	49	26
Balance at June 30, 2006	$ 7,464	$ 7,887

Stock Repurchases

On November 16, 2005, PG&E Corporation entered into an accelerated share repurchase arrangement, or ASR, with Goldman Sachs & Co. Inc., or GS&Co., under which PG&E Corporation repurchased and retired 31,650,300 shares of its outstanding common stock for an initial aggregate purchase price of approximately $1.1 billion, or $34.75 per share. Under the share forward agreement related to the ASR, certain additional payments were required by both PG&E Corporation and GS&Co., including a price adjustment based on the difference between the initial purchase price and the average of the daily volume weighted average price, or VWAP, of PG&E Corporation common stock over a seven-month period. The price adjustment and any additional payment obligations could be settled, at PG&E Corporation's option, in cash or in shares of its common stock, or a combination of the two. Until the ASR is completed or terminated, GAAP requires PG&E Corporation to assume that it will issue shares to settle its obligations. PG&E Corporation must calculate the number of shares that would be required to satisfy its obligations upon completion of the ASR based on the market price of PG&E Corporation's common stock at the end of a reporting period. The number of shares that would be required to satisfy the obligations must be treated as outstanding for purposes of calculating diluted EPS.

On March 28, 2006, the share forward agreement related to the ASR was terminated in accordance with its terms and on March 31, 2006, PG&E Corporation paid GS&Co. approximately $58 million (net of amounts payable by GS&Co. to PG&E Corporation), including a price adjustment based on the difference between $34.75 per share and the average of the VWAP of PG&E Corporation common stock from November 17, 2005 through March 28, 2006. PG&E Corporation has accounted for its payment obligation as equity with the payment of the obligation resulting in a reduction to common shareholders' equity.

On March 28, 2006, PG&E Corporation entered into a new share forward agreement with GS&Co. to complete the ASR. The March 28, 2006 share forward agreement was terminated in accordance with its terms on June 8, 2006. In connection with the termination, on June 13, 2006, PG&E Corporation paid GS&Co. approximately $56 million (net of amounts payable by GS&Co. to PG&E Corporation), including a price adjustment based on the difference between $34.75 per share and the average of the VWAP of PG&E Corporation common stock from March 29, 2006 through June 8, 2006. PG&E Corporation has accounted for its payment obligation as equity with the payment of the obligation resulting in a reduction to common shareholders' equity. PG&E Corporation has no remaining obligation under the ASR. To reflect the potential dilution that existed during the three and six months periods ended June 30, 2006 due to the share forward obligations that existed during these periods, PG&E Corporation treated approximately 1 million and 2 million, respectively, additional shares of PG&E Corporation common stock as outstanding for purposes of calculating diluted EPS for the three and six months ended June 30, 2006.

Dividends

On April 17, 2006, PG&E Corporation paid a common stock dividend of $0.33 per share. On February 16, 2006, the Utility paid a common stock dividend in the aggregate amount of $124 million. Approximately $115 million of the common stock dividend was paid to PG&E Corporation and the remainder was paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility.

On June 21, 2006, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.33 per share payable on July 15, 2006, to shareholders of record on July 3, 2006. On June 21, 2006, the Board of Directors of the Utility declared a common stock dividend in the aggregate amount of $124 million that was paid on June 22, 2006. Approximately $115 million of the common stock dividend was paid to PG&E Corporation and the remainder was paid to PG&E Holdings, LLC. PG&E Corporation and the Utility record common stock dividends declared to Reinvested Earnings.

On February 15, 2006, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock payable on May 15, 2006, to shareholders of record on April 28, 2006. On June 21, 2006, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock payable on August 15, 2006, to shareholders of record on July 31, 2006.

NOTE 6: EARNINGS PER COMMON SHARE

EPS is calculated utilizing the " two-class " method, by dividing the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders by the weighted average number of common shares outstanding during the period. In applying the "two-class" method, undistributed earnings are allocated to both common shares and participating securities. PG&E Corporation's Convertible Subordinated Notes are entitled to receive "pass-through dividends" prior to exercising the conversion option and meet the criteria of a participating security. The Convertible Subordinated Notes are convertible, at the option of the holders, into 18,558,655 common shares. All PG&E Corporation's participating securities participate on a 1:1 basis in dividends with common shareholders.

PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted EPS in accordance with SFAS No. 128, "Earnings Per Share," or SFAS 128. SFAS 128 requires that proceeds from the exercise of options and warrants shall be assumed to be used to purchase common shares at the average market price during the reported period. The incremental shares, the difference between the number of shares assumed issued upon exercise and the number of shares assumed purchased, must be included in the number of weighted average common shares used for the calculation of diluted EPS.

The following is a reconciliation of PG&E Corporation's net income and weighted average common shares outstanding for calculating basic and diluted EPS:

(in millions, except share amounts)	**Three Months Ended June 30,**		**Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Net income	$ 232	$ 267	$ 446	$ 485
Less: distributed earnings to common shareholders	115	112	229	223
Undistributed earnings	$ 117	$ 155	$ 217	$ 262
Common shareholders earnings				

Basic				
Distributed earnings to common shareholders	$ 115	$ 112	$ 229	$ 223
Undistributed earnings allocated to common shareholders	111	147	206	249
Total common shareholders earnings, basic	$ 226	$ 259	$ 435	$ 472
Diluted				
Distributed earnings to common shareholders	$ 115	$ 112	$ 229	$ 223
Undistributed earnings allocated to common shareholders	111	148	206	250
Total common shareholders earnings, diluted	$ 226	$ 260	$ 435	$ 473
Weighted average common shares outstanding, basic	346	370	345	379
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, basic	365	389	364	398
Weighted average common shares outstanding, basic	346	370	345	379
Employee share-based compensation and accelerated share repurchase program [1]	3	4	4	4
Weighted average common shares outstanding, diluted	349	374	349	383
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, diluted	368	393	368	402
Net earnings per common share, basic				
Distributed earnings, basic	$ 0.33	$ 0.30	$ 0.66	$ 0.59
Undistributed earnings, basic	0.32	0.40	0.60	0.66
Total	$ 0.65	$ 0.70	$ 1.26	$ 1.25
Net earnings per common share, diluted				
Distributed earnings, diluted	$ 0.33	$ 0.30	$ 0.66	$ 0.58
Undistributed earnings, diluted	0.32	0.40	0.59	0.65
Total	$ 0.65	$ 0.70	$ 1.25	$ 1.23

[1] Includes approximately 1 million and 2 million shares treated as outstanding in connection with the ASR for the three and six months ended June 30, 2006 respectively (see Note 5 for further discussion). The remaining approximately 2 million shares relate to share-based compensation and are deemed to be outstanding per SFAS No. 128 for the purpose of calculating EPS for the three and six months ended June 30, 2006.

Options to purchase PG&E Corporation common shares of 6,500 for the three months ended June 30, 2005 and 4,650 and 6,500 for the six months ended June 30, 2006 and June 30, 2005, respectively, were outstanding, but not included in the computation of diluted EPS because the option exercise prices were greater than the average market price. All options to purchase PG&E Corporation common shares for the three months ended June 30, 2006 have option exercise prices lower than the average market price and are included in the computation of diluted EPS.

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

NOTE 7: RISK MANAGEMENT ACTIVITIES

Commodity Procurement Activities

The Utility enters into contracts to procure electricity, natural gas, nuclear fuel and firm transmission rights. Except for contracts that meet the definition of normal purchases and sales, all derivative contracts including contracts designated as cash flow hedges of natural gas in the natural gas portfolios are recorded at fair value and presented as PRM assets and liabilities on the balance sheet. On PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets, PRM activities consist of $49 million in Current Assets - Prepaid expenses and other, $94 million in Other Noncurrent Assets - Other, $107 million in Current Liabilities - Other, and $1 million in Noncurrent Liabilities - Other as of June 30, 2006, and $140 million in Current Assets - Prepaid expenses and other, $212 million in Other Noncurrent Assets - Other, and $2 million in Current Liabilities - Other, as of December 31, 2005. However, since these contracts are used within the regulatory framework, regulatory accounts are recorded to offset the costs and proceeds of these derivatives recognized in earnings and subsequently recovered in regulated rates charged to customers.

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. The Utility is exposed to a concentration of credit risk associated with receivables from the sale of natural gas and electricity to residential and small commercial customers in northern and central California. However, this risk is limited. Credit risk exposure is mitigated by requiring deposits from new customers and from those customers whose past payment practices are below standard. A material loss associated with the regional concentration of retail receivables is not considered likely .

Additionally, the Utility has a concentration of credit risk associated with its wholesale counterparties mainly in the energy industry, including other 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. If a counterparty failed to perform on its contractual obligation to deliver electricity, then the Utility may need to procure electricity at current market prices, which may be higher than those originally contracted. However, credit losses attributable to receivables and electrical and gas procurement activities from both retail and wholesale customers and counterparties are expected to be recoverable from customers through rates and are, therefore, not expected to have a material impact on earnings.

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

The schedule below summarizes the Utility's net credit risk exposure, as well as the Utility's credit risk exposure to its wholesale customers or counterparties with a greater than 10% net credit exposure, at June 30, 2006 and December 31, 2005:

(in millions)	Gross Credit Exposure Before Credit Collateral [1]	Credit Collateral	Net Credit Exposure [2]	Number of Wholesale Customer or Counterparties >10%	Net Exposure to Wholesale Customer or Counterparties >10%
June 30, 2006	$ 254	$ 14	$ 240	2	$ 134
December 31, 2005	447	105	342	3	165

[1] Gross credit exposure equals mark-to-market value on financially settled contracts, 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 or liquidity. The Utility's gross credit exposure includes wholesale activity only.

[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.

NOTE 8: SHARE-BASED COMPENSATION

On January 1, 2006, the PG&E Corporation 2006 Long-Term Incentive Plan, or 2006 LTIP, became effective. The 2006 LTIP permits the award of various forms of incentive awards including stock options, stock appreciation rights, restricted stock awards, restricted stock units, performance shares, performance units, deferred compensation awards, and other stock-based awards to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive restricted stock and either stock options or restricted stock units under the formula grant provisions of the 2006 LTIP. A maximum of 12 million shares of PG&E Corporation common stock (subject to

adjustment for changes in capital structure, stock dividends, or other similar events) have been reserved for issuance under the 2006 LTIP, of which 11,452,345 shares were available for award at June 30, 2006.

The 2006 LTIP replaced the PG&E Corporation Long-Term Incentive Program, which expired on December 31, 2005. Awards made under the PG&E Corporation Long-Term Incentive Program before December 31, 2005 and that are still outstanding continue to be governed by the terms and conditions of the PG&E Corporation Long-Term Incentive Program. Some of the stock options that are still outstanding under the PG&E Corporation Long-Term Incentive Program have associated dividend equivalents.

Total compensation expense for share-based incentive awards was approximately $12 million and $38 million ($8 million and $23 million, after-tax) for the three and six months ended June 30, 2006, of which approximately $8 million and $27 million ($5 million and $16 million, after-tax) was recognized by the Utility.

As discussed in Note 2, “New and Significant Accounting Policies - Share-Based Payment,” effective January 1, 2006, PG&E Corporation adopted the fair value recognition provisions for share-based payment using the modified prospective application method provided by SFAS No. 123R.

Stock Options

Stock options are granted with an exercise price equal to the market price of PG&E Corporation’s stock at the date of grant and generally vest over 4 years of continuous service. The options have a 10-year contractual term.

The fair value of each stock option is estimated on the date of grant using the Black-Scholes valuation method. The weighted average grant date fair value of options granted using the Black-Scholes valuation method was $6.98 and $8.51 per share in 2006 and 2005, respectively. The significant assumptions used for shares granted in 2006 and 2005 were:

	2006	**2005**
Expected stock price volatility	22.1%	40.6%
Expected annual dividend payment	$ 1.32	$ 1.20
Risk-free interest rate	4.46%	3.74%
Expected life	5.6 years	5.9 years

Expected volatilities are based on historical volatility of PG&E Corporation’s common stock. The expected life of stock options is derived from historical data that estimates stock option exercise and employee departure behavior. The risk-free interest rate for periods within the contractual term of the stock option is based on the U.S. Treasury rates in effect at the date of grant.

The total intrinsic value of options exercised during the three and six months ended June 30, 2006 was approximately $12 million and approximately $61 million, respectively, of which approximately $7 million and approximately $32 million, respectively, was recorded by the Utility. The total intrinsic value of options exercised during the three and six months ended June 30, 2005 was approximately $30 million and approximately $90 million, respectively, of which approximately $15 million and approximately $39 million, respectively, was recorded by the Utility. Cash received from options exercised for the six months ended June 30, 2006 and 2005, was approximately $77 million and $190 million, respectively. The tax benefit from option exercises totaled $45 million for the period ended June 30, 2006, of which approximately $23 million was recognized by the Utility.

The following table summarizes stock option activity for PG&E Corporation and the Utility for the six months ended June 30, 2006:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2006	11,899,059	$ 23.26		
Granted [1]	12,457	37.47		
Exercised	(3,557,100)	21.73		
Forfeited or expired	(91,861)	25.25		
Outstanding at June 30, 2006	8,262,555	23.92	4.9	$ 126,940,668
Exercisable at June 30, 2006	5,820,923	19.02	3.8	$ 96,402,583

[1] No stock options were awarded to employees in 2006; however certain non-employee directors of PG&E Corporation were awarded stock options.

The following table summarizes stock option activity for the Utility for the six months ended June 30, 2006:

Options	Shares	Weighted Average Exercise Price	Weighted Average Remaining Contractual Term	Aggregate Intrinsic Value
Outstanding at January 1, 2006	7,371,761	$ 23.15		
Granted	-	-		
Exercised	(1,932,609)	22.19		
Forfeited or expired	(68,279)	25.39		
Outstanding at June 30, 2006	5,370,873	23.45	5.5	$ 85,030,193
Exercisable at June 30, 2006	3,620,388	19.40	4.5	$ 62,897,355

As of June 30, 2006, there was approximately $16 million of total unrecognized compensation cost, of which $12 million related to the Utility. That cost is expected to be recognized over a weighted average period of 1.9 years for both PG&E Corporation and the Utility.

Restricted Stock

During the six months ended June 30, 2006, PG&E Corporation awarded 525,425 shares of PG&E Corporation restricted common stock to eligible participants of PG&E Corporation and its subsidiaries, of which 365,870 shares were awarded to the Utility's eligible participants.

The restricted shares are held in an escrow account. The shares become available to the employees as the restrictions lapse. For the restricted stock awarded in 2003, the restrictions on 80% of the shares lapse automatically over a period of four years at the rate of 20% per year. Restrictions on the remaining 20% of the shares will lapse at a rate of 5% per year if PG&E Corporation's annual total shareholder return, or TSR, is in the top quartile of its comparator group as measured at the end of the immediately preceding year. For restricted stock awarded in 2005 and 2004, there are no performance criteria and the restrictions will lapse ratably over four years. For restricted stock awarded in 2006, the restrictions on 60% of the shares will lapse automatically over a period of three years at the rate of 20% per year. If PG&E Corporation's annual TSR is in the top quartile of its comparator group as measured for the three immediately preceding calendar years, the restrictions on the remaining 40% of the shares will lapse on the first business day of 2009. If PG&E Corporation's TSR is not in the top quartile for such period, then the restrictions on the remaining 40% of the shares will lapse on the first business day of 2011. Compensation expense related to the portion of the 2006 restricted stock award subject to conditions based on TSR is recognized over the shorter of the requisite service period and three years.

The tax benefit from restricted stock settlements totaled $4 million for the six months ended June 30, 2006, of which approximately

$2 million was recognized by the Utility. There was no tax benefit from restricted stock settlements for the three months ended June 30, 2006 for PG&E Corporation or the Utility.

The following table summarizes restricted stock activity for PG&E Corporation and the Utility for the six months ended June 30, 2006:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2006	1,399,990	$ 22.31
Granted	525,425	37.47
Vested	(493,874)	20.97
Forfeited	(78,428)	18.20
Nonvested at June 30, 2006	1,353,113	29.04

The following table summarizes restricted stock activity for the Utility for the six months ended June 30, 2006:

	Number of Shares of Restricted Stock	Weighted Average Grant-Date Fair Value
Nonvested at January 1, 2006	958,997	$ 22.47
Granted	365,870	37.47
Vested	(340,396)	21.08
Forfeited	(64,855)	19.36
Nonvested at June 30, 2006	919,616	29.18

As of June 30, 2006, there was approximately $24 million of total unrecognized compensation cost, of which $17 million related to the Utility. PG&E Corporation and the Utility expect to recognize this cost over a weighted average period of 1.8 years.

Performance Shares

During the six months ended June 30, 2006, PG&E Corporation awarded 525,425 performance shares to certain officers and employees of PG&E Corporation and its subsidiaries, of which 365,870 shares were awarded to certain Utility officers and employees. Performance shares are hypothetical shares of PG&E Corporation common stock that vest at the end of a three-year period and are settled in cash. Upon vesting, the amount of cash that recipients are entitled to receive is based on the average closing price of PG&E Corporation stock for the last 30 calendar days of the year preceding the vesting date and a payout percentage, ranging from 0% to 200%, as measured by PG&E Corporation's TSR relative to its comparator group.

The following table summarizes performance share activity for PG&E Corporation and the Utility for the six months ended June 30, 2006:

	Number of Performance Shares
Nonvested at January 1, 2006	803,975
Granted	525,425
Vested	-
Forfeited	(20,357)
Nonvested at June 30, 2006	1,309,043

The following table summarizes performance shares activity for the Utility for the six months ended June 30, 2006:

	Number of

	Performance Shares
Nonvested at January 1, 2006	566,086
Granted	365,870
Vested	-
Forfeited	(19,802)

Nonvested at June 30, 2006	912,154

Outstanding performance shares are classified as a liability on the Condensed Consolidated Financial Statements of PG&E Corporation and the Utility because the performance shares can only be settled in cash upon satisfaction of the performance criteria. The liability related to the performance shares is marked-to-market at each reporting date to reflect the market price of PG&E Corporation common stock and the payout percentage at the end of the reporting period. Accordingly, compensation expense recognized for performance shares will fluctuate with PG&E Corporation's common stock price and its performance relative to its peer group.

NOTE 9: RELATED PARTY AGREEMENTS AND TRANSACTIONS

In accordance with various agreements, the Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced either at the fully loaded cost (*i.e.* , direct costs and allocations of overhead costs) or at the higher of fully loaded cost or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are priced either at the fully loaded cost or at the lower 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, at cost, to the Utility and other subsidiaries using agreed upon allocation factors, including the number of employees, operating expenses excluding fuel purchases, total assets, and other cost allocation methodologies. The Utility's significant related party transactions and related receivable (payable) balances were as follows:

(in millions)	Three Months Ended June 30,		Six Months Ended June 30,		Receivable (Payable) Balance Outstanding at	
					June 30,	December 31,
	2006	2005	2006	2005	2006	2005
Utility revenues from:						
Administrative services provided to PG&E Corporation	$ 1	$ 1	$ 2	$ 2	$ 1	$ 2
Utility employee benefit assets due from PG&E Corporation	(1)	-	(2)	-	21	23
Interest from PG&E Corporation on employee benefit assets	1	-	1	-	-	-
Utility expenses from:						
Administrative services received from PG&E Corporation	$ 9	$ 24	$ 48	$ 49	$ (31)	$ (37)

NOTE 10: THE UTILITY'S EMERGENCE FROM CHAPTER 11

The Utility emerged from Chapter 11 when its plan of reorganization became effective on April 12, 2004. The plan of reorganization incorporated the terms of the Settlement Agreement. Although the Utility's operations are no longer subject to the oversight of the Bankruptcy Court, the Bankruptcy Court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Settlement Agreement, (2) the plan of reorganization, and (3) the Bankruptcy Court's December 22, 2003 order confirming the plan of reorganization, or confirmation order. In addition, the Bankruptcy Court retains jurisdiction to resolve remaining disputed claims. Refer to the 2005 Annual Report for a further discussion of the Utility's emergence from Chapter 11.

On March 16, 2006, the U.S. Court of Appeals for the Ninth Circuit, or Ninth Circuit, dismissed as moot an appeal of the confirmation order. The appeal had been filed by two former commissioners of the CPUC who did not vote to approve the Settlement Agreement. On March 30, 2006, one of the two former commissioners filed a petition for rehearing with the Ninth Circuit. On April 7, 2006, the Ninth Circuit denied the petition. The time period during which the former commissioners could have filed a petition for rehearing with the U.S. Supreme Court has expired, rendering the confirmation order final and no longer subject to appeal.

As of June 30, 2006 and December 31, 2005, the Utility had accrued approximately $1.2 billion for remaining net disputed claims, consisting of approximately $1.7 billion of accounts payable-disputed claims primarily payable to the California Independent System Operator, or ISO, and the California Power Exchange, or PX, offset by an accounts receivable amount from the ISO and the PX of approximately $0.5 billion. The Utility held approximately $1.2 billion in escrow, which

is recorded as restricted cash, for the payment of the remaining disputed claims as of June 30, 2006 and December 31, 2005. Upon resolution of these claims and under the terms of the Settlement Agreement, any net refunds, claims offsets or other credits that the Utility receives from energy suppliers will be returned to customers. With the approval of the Bankruptcy Court, the Utility has withdrawn certain amounts from escrow in connection with settlements with certain ISO and PX sellers.

NOTE 1 1: 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.

Commitments

PG&E Corporation

In addition to material commitments related to the Utility and disclosed elsewhere in the Notes to the Condensed Consolidated Financial Statements at June 30, 2006, PG&E Corporation has a commitment relating to natural gas pipeline firm transportation contracts effective November 1, 2007 through October 31, 2023. The firm quantity under the contracts is approximately 50 million cubic feet per day and PG&E Corporation has estimated annual reservation charges will range between approximately $8 million and $10 million.

Utility

Power Purchase Agreements

As part of the ordinary course of business, throughout the year, the Utility enters into various agreements to purchase energy and makes payments on existing power purchase agreements. At June 30, 2006, the expected payments for power purchase agreements based on June 30, 2006 forward prices were as follows:

(in millions)		
2006	$	1,235
2007		2,322
2008		2,197
2009		1,884
2010		1,611
Thereafter		11,216
Total	$	20,465

Payments made by the Utility under power purchase agreements amounted to approximately $1,038 million for the six months ended June 30, 2006, and $905 million for the same period in 2005. As the Utility acts as only an agent for the Department of Water Resources, or DWR, the amounts described above do not include DWR power purchases.

The CPUC is considering various policy and pricing issues related to power purchased from QFs in several rulemaking proceedings. It is expected that a proposed decision addressing those issues will be issued soon. In April 2006, the Utility and the Independent Energy Producers on behalf of certain QFs entered into a settlement agreement to resolve these issues irrespective of how the CPUC ultimately resolves these issues. The settlement agreement required settling QFs to enter into an amendment of their existing contracts with the Utility to reduce the Utility’s energy payments and to establish a new five-year fixed pricing option for non-natural gas-fired QFs. On July 20, 2006, the CPUC approved the settlement agreement and amendments relating to 121 QFs, representing 52% of the Utility’s 2004 QF energy deliveries. The settlement agreement also resolves certain energy crisis claims among the Utility and the settling QFs that are pending in another CPUC proceeding. The settlement agreement and the amendments will become effective after the CPUC decision becomes final and non-appealable on August 21, 2006, assuming no application for rehearing is filed by that date.

Natural Gas Supply and Transportation Commitments

The Utility purchases natural gas directly from producers and marketers in both the United States and Canada to serve its residential and small commercial, or 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.

At June 30, 2006, the Utility's expected payments for natural gas purchases based on June 30, 2006 forward prices and gas transportation services based on existing contract prices were as follows:

(in millions)		
2006	$	513
2007		415
2008		30
2009		25
2010		8
Thereafter		-
Total	$	991

Payments made by the Utility for natural gas purchases and gas transportation services amounted to approximately $1,275 million for the six months ended June 30, 2006, and $1,108 million for the same period in 2005.

Nuclear Fuel Agreements

The Utility has entered into purchase agreements for nuclear fuel. These agreements have terms ranging from three to six years and are intended to ensure long-term fuel supply. Pricing terms also are diversified, ranging from fixed prices to market-based prices to base prices that are escalated using published indices.

At June 30, 2006, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)		
2006	$	114
2007		89
2008		85
2009		66
2010		78
Thereafter		143
Total	$	575

Payments made by the Utility for nuclear fuel amounted to approximately $22 million for the six months ended June 30, 2006, and approximately $18 million for the same period in 2005.

Reliability Must Run Agreements

The ISO has entered into reliability must run, or RMR, agreements with various power plant owners, including the Utility, that require designated units in certain power plants, known as RMR units, to remain available to generate electricity upon the ISO's demand when needed for local transmission system reliability. As a participating transmission owner under the Transmission Control Agreement, the Utility is responsible for the ISO's costs paid under RMR agreements to power plant owners within or adjacent to the Utility's service territory. At June 30, 2006, the Utility estimated that it could be obligated to pay the ISO approximately $130 million for costs to be incurred under these RMR agreements during the period July 1, 2006 to December 31, 2006. RMR agreements are established or extended on an annual basis, and the ISO will announce the proposed 2007 agreements in September 2006. It is likely that the number of RMR agreements and the associated costs will be reduced in 2007 because many or all local transmission system reliability issues may be addressed through the CPUC’s Local Resource Adequacy Requirements proceeding.

The Utility recovers those costs it incurs under RMR agreements in rates from customers under the Utility’s FERC-jurisdictional transmission owner tariff, without mark-up or service fees. The Utility tracks these costs and related recoveries in the reliability services balancing account. Periodically, the Utility’s electricity transmission rates are adjusted to refund over-collections to the Utility’s customers or to collect any under-collections from customers. Of the $130 million estimated obligation to the ISO, the Utility estimates it will receive approximately $15 million during the same period under the RMR agreements the Utility has with the ISO for the Utility’s units that have been designated as RMR units.

In November 2001, the Utility and other interested California parties filed a complaint with the FERC against RMR owners other than the Utility, alleging certain rates under those owners' RMR agreements with the ISO were unlawfully high and proposing the FERC apply a ratemaking methodology to these other RMR agreements that would significantly reduce those rates. The FERC dismissed the complaint in 2005. In September 2005, the Utility and other interested California parties filed a petition for review of the FERC's decision with the United States Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. On June 19, 2006, the D.C. Circuit granted the FERC's requested remand of the appeal to permit further consideration of the case. If the FERC applies the ratemaking methodology proposed in the complaint, the Utility may be able to obtain a refund of RMR charges of approximately $50 million that would be credited to the Utility's electricity customers. PG&E Corporation and the Utility are unable to predict the outcome of this matter.

In November 2005, two affiliates of Calpine Corporation filed an application with the FERC for approval of large proposed rate increases for fixed-cost payments under the RMR contracts for the Delta Energy Center and Los Esteros Critical Energy Facility. The proposed rates would increase the Utility's combined RMR payments for these facilities by approximately $70 million per year over the amounts paid in 2005. On January 26, 2006, the FERC made these rates effective, subject to hearing and possible refund. The FERC deferred the hearing and directed the parties to engage in settlement efforts. On February 28, 2006, the Utility filed a complaint with the FERC alleging these affiliates of Calpine Corporation violated the FERC's market behavior rule that prohibits furnishing false or misleading information to independent system operators, among others, because the proposed rates were far higher than their July 2005 bids to the ISO for RMR service in 2006. This complaint asked the FERC to reduce the rates for these RMR units to a level no higher than would have resulted from these bids. On July 3, 2006 the FERC issued an order dismissing the complaint, and the Utility has 30 days to seek rehearing. Any refunds the Utility may obtain when these cases are decided will be credited to the Utility's electricity customers. In addition, on August 1, 2006, the Utility filed claims in the Chapter 11 proceedings of several affiliates of Calpine Corporation that own RMR plants seeking refunds of RMR costs that the Utility paid in the approximate aggregate amount of $98 million. Any funds the Utility may obtain upon resolution of these Chapter 11 proceedings will be credited to the Utility's electric customers. PG&E Corporation and the Utility are unable to predict the outcome of these matters.

Underground Electric Facilities

At June 30, 2006, the Utility was committed to spending approximately $230 million for the conversion of existing overhead electric facilities to underground electric facilities. These funds are conditionally committed depending on the timing of the work, including the schedules of the respective cities and counties and telephone utilities involved. The Utility expects to spend approximately $50 million to $55 million each year in connection with these projects. Consistent with past practice, the Utility expects that these capital expenditures will be included in rate base as each individual project is completed and recoverable in rates charged to customers.

Contingencies

PG&E Corporation

PG&E Corporation retains a guarantee of up to $150 million related to certain indemnity obligations of its former subsidiary, National Energy & Gas Transmission, Inc., or NEGT, that were issued to the purchaser of an NEGT subsidiary company during 2000. The underlying indemnity obligations of NEGT have expired and PG&E Corporation's sole remaining exposure relates to any potential environmental obligations that were known to NEGT at the time of the sale but not disclosed to the purchaser. PG&E Corporation has never received any claims nor does it consider it probable any claims will be made under the guarantee. Accordingly, PG&E Corporation has made no provision for this guarantee at June 30, 2006.

Utility

PX Block-Forward Contracts

In February 2001, during the energy crisis, the California Governor seized all of the Utility's contracts for the forward delivery of power in the PX California market, otherwise known as "block-forward contracts," for the benefit of the state under California's Emergency Services Act. These block-forward contracts had an estimated unrealized value 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 competing claims in state court against the State of California to recover the value of these seized contracts. In November 2005, the PX assigned its interest in this litigation to certain market participants that elected to take assignment of the litigation, subject to the terms and conditions of a settlement agreement approved by the FERC. A motion by the PX for court approval of the assignment is pending in the Sacramento Superior Court. The State of California disputes this assignment and the plaintiffs' rights to recover the value of the contracts and also disputes plaintiffs' contentions that the contracts had any value beyond the price at which the block-forward transactions were executed. This state court litigation is pending. Although the Utility has recorded a receivable of approximately $243 million relating to the estimated value of the contracts at the time of seizure, the Utility also has established a reserve of $243 million for these contracts. If the Utility ultimately prevails, it would record income in the amount of any recovery. PG&E Corporation and the Utility are unable to predict the outcome of this litigation or the amount of any potential recovery.

California Energy Crisis Proceedings

FERC Proceedings

Various entities, including the Utility and the State of California, are seeking refunds from energy suppliers in the California ISO and PX markets for electricity overcharges on behalf of California electricity purchasers for the period May 2000 to June 2001 through various proceedings pending at the FERC and judicial proceedings. Refer to the 2005 Annual Report for a further discussion of the Utility's California energy crisis proceedings.

The FERC established a refund methodology and directed the ISO and the PX to make compliance filings to enable the FERC to establish the amount of refunds. The ISO had previously indicated that it planned to make its compliance filing in the first quarter of 2006 with the PX to follow. However, the ISO cannot make its filing until the FERC rules on pending claims made by energy suppliers for recovery of certain costs that could offset any refunds that the FERC determines those suppliers owe. Therefore, it is not known when the ISO and PX will make their compliance filings.

In September 2005, the Ninth Circuit issued a partial decision finding that the FERC did not have the authority to order governmental and municipal utilities to provide refunds. This decision remains subject to rehearing or further appellate review. On March 16, 2006, the California utilities and the California Electric Oversight Board filed a lawsuit against 19 municipal and governmental entities seeking refunds. Additional refund claims also are being pursued against three other governmental entities. Based on preliminary rulings by a FERC administrative law judge, the amount being sought by the California utilities in the claims against the governmental and municipal entities is estimated to be approximately $150 million or more. A further Ninth Circuit decision on the extent of the FERC's power to order refunds from other sellers is still pending. Final refunds will not be determined until the FERC issues a final order after the ISO and PX compliance filings are made and after the resolution of appeals.

The Utility has entered into settlements with various power suppliers resolving certain disputed claims and the Utility's refund claims against these power suppliers. The Utility has recorded credits of approximately $1 billion under these settlements (including the settlements described below). These settlement agreements provide that the amounts payable by the parties are subject to adjustment based on the ultimate judicial determination of the FERC's refund authority, and the FERC's final decisions regarding refund amounts, cost filings, gas and emissions recovery and allocation, and interest. Future amounts received under these settlements, and any future settlements with energy suppliers, will be credited to customers, except for those related to wholesale power purchasers.

Enron Settlement

In November 2005, the FERC approved an agreement among the Utility, the California Attorney General, the DWR, Southern California Edison, San Diego Gas & Electric Company, the California Electric Oversight Board and the CPUC (collectively, the California Parties), along with the Attorney Generals of the States of Oregon and Washington, the FERC's Office of Market Oversight and Investigations (collectively, the Other Parties), and Enron Corporation and various of its subsidiaries, or Enron, to satisfy Enron's liabilities to make refunds.

The settlement provides Enron would pay $47 million in cash to the California Parties and the Other Parties and allow them an unsecured claim of $875 million in the bankruptcy proceedings of Enron Power Marketing, Inc., a subsidiary through which Enron conducted its power marketing operations in California, to settle electric and gas market overcharges. Of these amounts, the Utility expects to receive approximately $12 million in cash, over time, and approximately $345 million of the unsecured bankruptcy claim. In February 2006, the Utility received cash proceeds of approximately $20 million, consisting of $5 million from the cash portion of the settlement proceeds and $15 million as a partial distribution of the allowed unsecured bankruptcy claim, which was credited to customers. In April 2006, the Utility received a second distribution on its allowed unsecured bankruptcy claim, consisting of $41 million in cash and 281,828 shares of Portland General Electric common stock. The Utility subsequently sold all of the shares of Portland General Electric common stock, realizing approximately $8 million in net proceeds. The cash proceeds from both the second distribution and the sale of the stock, after deductions for contingencies, amounts related to certain wholesale power purchases and amounts due to shareholders, were credited to customers. The final value of the bankruptcy claim will not be determined until the conclusion of Enron's bankruptcy case unless liquidated earlier in a secondary market for such claims.

Reliant Settlement

In December 2005, the FERC approved an agreement among the Utility, the Attorney Generals of the States of Oregon and Washington, the DWR, the FERC's Office of Market Oversight and Investigations, Southern California Edison, San Diego Gas & Electric Company, and Reliant Energy, Inc. and various of its subsidiaries, or Reliant, to resolve claims against Reliant for gas and electric market manipulation and overcharges during the California energy crisis in 2000 and 2001.

Under the terms of the agreement, Reliant assigned to the counterparties approximately $300 million of its receivables from the ISO or the PX and agreed to pay the counterparties an additional $131 million in cash. In 2005, the Utility recognized approximately $105 million of its share of Reliant's assigned receivable from the ISO or the PX as a reduction in the Utility's payable to the PX. Additionally, in March 2006, the Utility received approximately $88 million in cash for its share of initial cash proceeds. These proceeds, after deductions for contingencies, amounts related to certain wholesale power purchases and amounts due to shareholders, have been credited to the Utility's customers. The Utility expects to receive additional cash proceeds of approximately $10 million over time.

Mirant Settlement

In January 2005, the Utility and other parties entered into a settlement agreement with Mirant Corporation and certain of its subsidiaries, or Mirant, related to claims outstanding in Mirant's Chapter 11 proceeding. The FERC and Mirant's bankruptcy court approved the settlement in April 2005.

The first part of the two-part settlement is among Mirant, the California Attorney General's Office, the DWR, the CPUC, Southern California Edison, San Diego Gas & Electric Company, and the Utility, among others, resolving market manipulation claims against Mirant and Mirant's liability for FERC refunds, penalties and civil liabilities arising out of the California energy crisis in 2000 and 2001. Under this portion of the agreement, Mirant provided approximately $320 million in cash equivalents and $175 million of allowed claims in the bankruptcy proceeding of Mirant America's Energy Marketing, LP. Of these amounts, the Utility received approximately $134 million in a combination of cash and a cash-equivalent reduction in the Utility's payable to the PX. Additionally, the Utility received approximately $45 million in allowed claims excluding interest, which the Utility sold in December 2005 for approximately $48 million, including interest owed by Mirant. The consideration received, after deductions for contingencies, amounts related to certain wholesale power purchases and amounts due to shareholders, has been credited to the Utility's customers.

The second part of the settlement is between the Utility and Mirant, and is designed to settle claims that Mirant overcharged the Utility under Mirant's RMR contracts and other disputes. In January 2006, under the terms of the settlement agreement, the Utility received consideration, in the form of cash and new Mirant stock, of approximately $43 million in settlement of an RMR claim and $20 million in settlement of a claim relating to sulfur dioxide emission allowances. These proceeds were credited to the Utility's customers during the quarter ended March 31, 2006. In addition, Mirant agreed to transfer to the Utility the equipment, permits and contracts for the construction of a modern 530-megawatt, or MW, electric generating facility known as Contra Costa Unit 8, that Mirant started to build but never completed. On June 13, the FERC authorized Mirant to transfer Contra Costa Unit 8 to the Utility. On June 15, 2006, the CPUC approved the Utility's application to acquire Contra Costa Unit 8, to complete construction, and to operate the facility. The completion of the acquisition remains subject to the satisfaction of a number of closing conditions. If the Utility and Mirant do not close the acquisition of Contra Costa Unit 8 on or before June 30, 2008, the Utility will be paid $70 million from an escrow account funded by Mirant in lieu of transferring the assets. The settlement agreement also includes a contract that gives the Utility the right, from 2006 through 2012, to dispatch power from certain RMR units owned by Mirant subsidiaries, subject to continued RMR status, when the facilities are not needed by the ISO to meet local reliability needs. In addition, Mirant has withdrawn the claim that it filed in the Utility's bankruptcy proceeding of approximately $20 million.

Scheduling Coordinator Costs

Before the ISO commenced operation in 1998, the Utility had entered into several wholesale electric transmission contracts with various governmental entities. After the ISO began operations, the Utility served as the scheduling coordinator, or SC, with the ISO for these existing wholesale transmission customers, or ETCs. The ISO billed the Utility for providing certain services associated with this scheduling. These ISO charges are referred to as "SC costs." The SC costs were initially tracked in the transmission revenue balancing account, or TRBA, in order to recover the SC costs from retail and new wholesale transmission customers, or TO Tariff customers.

In 1999, a FERC administrative law judge, or ALJ, ruled that the Utility could not recover the SC costs through the TRBA and instead should seek to recover the SC costs from the ETCs. The Utility appealed this ruling. In January 2000, the

FERC accepted a filing by the Utility to establish the Scheduling Coordinator Services, or SCS, Tariff, to serve as an alternative mechanism for recovery of the SC costs from the ETCs in case the Utility's appeal was unsuccessful and the Utility was ultimately unable to recover these costs in the TRBA . In August 2002, the FERC affirmed the ALJ's 1999 ruling that the Utility should refund to TO Tariff customers the SC costs that the Utility had collected through the TRBA. In the absence of an order from the FERC granting recovery of these costs through the TRBA, the Utility removed the SC costs from the TRBA and reflected the SC costs as accounts receivable under the SCS Tariff. The Utility appealed the FERC's decision to the D.C. Circuit. In June 2004, the Utility began billing the ETCs under the SCS Tariff for SC charges retroactive to April 1, 1998. In the course of the SCS Tariff proceeding at the FERC, the Utility entered into settlement agreements with several ETCs under which the settling ETCs paid the Utility compromised amounts in full satisfaction of past due SC costs. Most of the settlement agreements provided that if the Utility's pending appeal to the D.C. Circuit was successful the Utility would refund the settlement amounts paid by the ETCs.

In July 2005, the D.C. Circuit issued an order finding that the Utility was not barred from recovering the SC costs through the TRBA and remanding the matter to the FERC for further action. In December 2005, the FERC issued an order concluding that the Utility should recover the SC costs through the TRBA mechanism or through bilateral agreements with the ETCs, but could not recover the costs through the SCS Tariff, and terminating the SCS Tariff proceeding. On May 22, 2006, the FERC issued an order further clarifying that the Utility could recover through the TRBA all of the costs that it had incurred as an SC and ordered the Utility to refund to the ETCs all amounts paid by the ETCs to the Utility pursuant to the SCS Tariff. As of July 31, 2006, the Utility had made refunds to the ETCs pursuant to the FERC's May 2006 order and the settlement agreements that required refunds to be made if the Utility's appeal was successful.

On April 4, 2006, the Utility filed an application with the FERC seeking approval of the $109 million that the Utility recorded as SC costs from April 1998 through September 30, 2005, together with interest of $47 million accrued over that time period. The Utility requested that the FERC permit the Utility to recover these costs from TO Tariff customers over three and one half years. On June 22, 2006, the Utility filed additional information to supplement the application as directed by the FERC. Unless the FERC requests additional information, the Utility expects a FERC order on the application before September 1, 2006. The Utility also filed an advice letter with the CPUC notifying the CPUC that the Utility will seek to pass through the portion of any FERC-approved SC costs that is allocable to the Utility's retail electric customers. In light of these events, in the quarter ended June 30, 2006, the Utility's net income increased by approximately $22 million, or $36 million pre-tax, reflecting the portion of SC costs determined to be probable of recovery through the TRBA and the reversal of a reserve for SC costs under the SCS Tariff which was terminated by FERC, offset by the SCS refunds to the ETCs.

The Utility cannot predict when a final decision will be received from the FERC or the CPUC or what impact it will have. While PG&E Corporation and the Utility believe that 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, the Utility's net income could increase by approximately $40 million if the FERC ultimately approves for recovery all of the costs included in the April 4, 2006 filing and the CPUC approves the portion of any FERC-approved SC costs that is allocable to the Utility's retail electric customers.

Nuclear Insurance

The Utility has several types of nuclear insurance for Diablo Canyon and its retired nuclear facility at Humboldt Bay, or 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 for Diablo Canyon. In addition, NEIL provides $131 million of property damage insurance for Humboldt Bay Unit 3. Under this insurance, if any nuclear generating facility insured by NEIL suffers a catastrophic loss causing a prolonged outage, the Utility may be required to pay an additional premium of up to $42.9 million per one-year policy term.

NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants. If one or more acts of domestic terrorism cause property damage covered under any of the nuclear insurance policies issued by NEIL to any NEIL member within a 12-month period, the maximum recovery under all those nuclear insurance policies may not exceed $3.24 billion plus the additional amounts recovered by NEIL for these losses from reinsurance. There is no policy coverage limitation for an act caused by foreign terrorism because NEIL would be entitled to receive substantial reimbursement by the federal government under the Terrorism Risk Insurance Extension Act of 2005. The Terrorism Risk Insurance Extension Act of 2005 expires on December 31, 2007.

Under the Price-Anderson Act, public liability claims from a nuclear incident are limited to $10.8 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of $300 million for Diablo Canyon. The balance of the $10.8 billion of liability protection is covered by a loss-sharing program among utilities owning nuclear reactors. Under the Price-Anderson Act, owner participation in this loss-sharing program is required for all owners of nuclear reactors that are licensed to operate, designed for the production of electrical energy, and have a rated capacity of 100 MW or higher. If a nuclear incident results in costs in excess of $300 million, then the Utility may be responsible for up to $100.6 million per reactor, with payments in each year limited to a maximum of $15 million per incident until the Utility has fully paid its share of the liability. Since Diablo Canyon has two nuclear reactors each with a rated capacity of over 100 MW, the Utility may be assessed up to $201.2 million per incident, with payments in each year limited to a maximum of $30 million per incident. Under the Energy Policy Act of 2005, the Price-Anderson Act was extended through December 31, 2025. Both the maximum assessment per reactor and the maximum yearly assessment will be adjusted for inflation beginning August 31, 2008.

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 Nuclear Regulatory Commission, for public liability arising from nuclear incidents covering liabilities in excess of the $53.3 million of liability insurance .

California Department of Water Resources Contracts

Electricity from the DWR contracts to the Utility provided approximately 23% of the electricity delivered to the Utility's customers for the six months ended June 30, 2006. The DWR purchased the electricity under contracts with various generators. The Utility, as an agent, is responsible for administration and dispatch of the DWR's electricity procurement contracts allocated to the Utility for purposes of meeting a portion of the Utility's net open position. The Utility's net open position is the portion of the Utility's customers' demand, plus the applicable reserve margins, that is not satisfied from the Utility's own generation facilities and existing electricity contracts. The DWR remains legally and financially responsible for its electricity procurement contracts. The Utility acts as a billing and collection agent of the DWR's revenue requirements from the Utility's customers.

The DWR contracts currently allocated to the Utility terminate at various dates through 2015 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 facilities 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 the Utility dispatches the resource and the resource delivers the required electricity. In the Utility's CPUC-approved long-term electricity procurement plan, the Utility has not assumed the DWR contracts will be renewed beyond their current expiration dates.

The DWR has stated publicly in the past 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 the CPUC will not require the Utility to accept an assignment of, or to assume legal or financial responsibility for, the DWR power purchase contracts unless each of the following conditions has been met:

- After assumption, the Utility's issuer rating by Moody’s Investors Service will be no less than A2 and the Utility's long-term issuer credit rating by Standard and Poor’s Ratings Service 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.

Severance

In connection with the Utility’s continued effort to streamline processes and focus on the customer, jobs from numerous locations around California are being consolidated. As a result, the Utility will be eliminating a number of positions by the end of 2007, with impacted employees being offered the option to elect severance or reassignment.

As of June 30, 2006 the Utility has not recorded an accrual for severance because the cost is not currently estimable. Severance cost will vary widely primarily based on the employees’ decision to elect either severance or reassignment. Depending on the election, costs will further vary based on the employees’ seniority level (including their years of experience and retirement eligibility) and the number, type, and location of positions available for reassignment. Given the uncertainty of each of these variables, the ultimate number of positions that will be eliminated, and the lack of historical data to assist

with predicting employee preferences, the Utility is unable to estimate the cost of severance associated with the streamlining processes. However, under the Utility's existing severance plan, these costs could range from $0 to approximately $55 million.

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 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 $514 million at June 30, 2006, and approximately $469 million at December 31, 2005. The increase in the undiscounted environmental remediation liability is partly due to a $30 million increase in estimated costs as a result of changes in the California Regional Water Quality Control Board's imposed remediation levels associated with the Utility's gas compressor station located near Hinkley, California. Costs incurred at this facility are not recoverable from customers and, as a result net income was reduced by $18 million for the three and six months ended June 30, 2006. In addition, the Utility increased its estimated remediation costs associated with its gas compressor station located near Topock, Arizona by $24 million. In accordance with the hazardous waste ratemaking mechanism discussed below, 90% of this additional cost will be recoverable in rates. The $514 million accrued at June 30, 2006, includes approximately $237 million for remediation at gas compressor sites, approximately $100 million related to the pre-closing remediation liability associated with divested generation facilities, and approximately $177 million related to remediation costs for those generation facilities that the Utility still owns, gas gathering sites, 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 $514 million environmental remediation liability, approximately $139 million has been included in prior rate setting proceedings. The Utility expects that an additional approximately $250 million will be allowable for inclusion in future rates in accordance with the hazardous waste ratemaking mechanism which permits the Utility to recover 90% of hazardous waste remediation costs from customers without a reasonableness review. The Utility also recovers its costs from insurance carriers and from other third parties whenever possible. Any amounts collected in excess of the Utility's ultimate obligations may be subject to refund to customers.

The Utility's undiscounted future costs could increase to as much as $782 million if the other potentially responsible parties are not financially able to contribute to these costs, or if the extent of contamination or necessary remediation is greater than anticipated. The amount of approximately $782 million does not include an estimate for the cost of remediation at known sites owned or operated in the past by the Utility's predecessor corporations for which the Utility has not been able to determine whether a liability exists.

Taxation Matters

The Internal Revenue Service, or IRS, has completed its audit of PG&E Corporation's 1997 and 1998 consolidated federal income tax returns and has assessed additional federal income taxes of approximately $87 million (including interest). PG&E Corporation has filed protests contesting certain adjustments made by the IRS in that audit. In April 2006, PG&E Corporation and the IRS Appeals Office resolved the remaining contested adjustment. The IRS Appeals Office is incorporating the results into its final report. However, the IRS Appeals Office has not indicated when it will complete its report.

The IRS is currently auditing PG&E Corporation's 2001 and 2002 consolidated federal income tax returns. The IRS is proposing to disallow a number of deductions claimed in PG&E Corporation's 2001 and 2002 tax returns. The largest of these deductions is a deduction for abandoned or worthless assets owned by NEGT. In addition, the IRS is proposing to disallow $104 million of synthetic fuel credits claimed in PG&E Corporation's 2001 and 2002 tax returns. If the IRS includes all of its proposed disallowances in its final Revenue Agent Report, the alleged tax deficiency would approximate $452 million. PG&E Corporation believes that it properly reported these transactions in its tax returns and will contest any IRS assessment. The IRS has indicated that it plans to complete its audit of PG&E Corporation's 2001 and 2002 tax returns and issue a Revenue Agent Report in the first quarter of 2007.

The IRS is also in the early stages of an audit of PG&E Corporation's 2003 and 2004 consolidated federal income tax returns and has not yet proposed any new adjustments to these tax returns.

As of June 30, 2006, PG&E Corporation has accrued approximately $138 million to cover potential non-Utility tax obligations and interest related to outstanding audits, including $89 million related to the proposed disallowance of deduction for abandoned or worthless assets owned by NEGT discussed above, and $49 million to cover potential tax obligations related to non-NEGT issues. The Utility has accrued $52 million as of June 30, 2006 to cover potential tax obligations for outstanding audits.

After considering the above accruals, PG&E Corporation and the Utility do not expect the final resolution of the outstanding audits to have a material impact on their financial condition or results of operations .

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.

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. In assessing such contingencies, PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs.

The accrued liability for legal matters is included in PG&E Corporation's and the Utility's other current liabilities in the Condensed Consolidated Balance Sheets, and totaled approximately $60 million at June 30, 2006 and $388 million at December 31, 2005. The decrease in the accrued liability for legal matters is primarily due to payments made under the chromium litigation settlement agreement discussed below.

PG&E Corporation and the Utility do not believe it is probable that losses associated with legal matters that exceed amounts already recognized will be incurred in amounts that would be material to PG&E Corporation's or the Utility's financial condition or results of operations .

Chromium Litigation

In accordance with the terms of a settlement agreement entered into on February 3, 2006, on April 21, 2006, the Utility released $295 million from escrow for payment to approximately 1,100 plaintiffs who had filed complaints against the Utility in the Superior Court for the County of Los Angeles, or Superior Court. The Superior Court has dismissed the ten complaints covered by the settlement agreement. There are three complaints filed by approximately 125 plaintiffs who did not participate in the settlement that are still pending in the Superior Court. The plaintiffs allege that exposure to chromium at or near the Utility's compressor station at Hinkley, California, caused personal injuries, wrongful deaths, or other injuries.

With respect to the unresolved claims, the Utility will continue to pursue appropriate defenses, including the statute of limitations, the exclusivity of workers' compensation laws, lack of exposure to chromium, and the inability of chromium to cause certain of the illnesses alleged.

PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets at June 30, 2006, include an accrual of approximately $19 million to reflect the remaining unresolved claims. PG&E Corporation and the Utility do not expect that the outcome with respect to the remaining unresolved claims will have a material adverse effect on their financial condition or results of operations.

Pending CPUC Investigation

In February 2005, the CPUC issued a ruling opening an investigation into the Utility’s billing and collection practices and credit policies. The investigation was begun at the request of The Utility Reform Network, or TURN, after the CPUC's January 13, 2005 decision that characterized the definition of “ billing error ” in a revised Utility tariff to include delayed bills and Utility-caused estimated bills as being consistent with “ existing CPUC policy, tariffs, and requirements. ” The Utility contends that prior to the CPUC’s January 13, 2005 decision, “ billing error ” under the Utility's former tariffs did not encompass delayed bills or Utility-caused estimated bills. The Utility’s petition asking the appellate court to review the CPUC's decision denying rehearing of its January 13, 2005 decision is still pending.

On February 3, 2006, the CPUC’s Consumer Protection and Safety Division, or CPSD, and TURN submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills. The CPSD recommended that the Utility refund to customers $117 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. TURN recommended that the Utility refund to customers $53 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. The two refunds are not additive. The CPSD also recommended that the Utility pay fines of $6.75 million, while TURN recommends fines in the form of a $1 million contribution to Relief for Energy Assistance through Community Help. Both the CPSD and TURN recommend that refunds and fines be funded by shareholders. In May and July 2006, the CPSD and TURN indicated they had reduced their recommended refund amounts to approximately $54 million and $36 million, respectively, plus interest at the three-month commercial paper interest rate . A decision is expected from the CPUC by the end of 2006.

If the CPUC finds that the Utility violated applicable tariffs or the CPUC’s orders or rules, the CPUC may seek to order the Utility to refund any amounts collected in violation of tariffs, plus interest, to customers who paid such amounts. In addition, if the CPUC finds that the Utility violated applicable tariffs or the CPUC’s orders or rules, the CPUC may seek to impose penalties on the Utility.

PG&E Corporation and the Utility do not expect that the outcome of this matter will have a material adverse effect on their financial condition or results of operations .

ITEM 2: MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation, incorporated in California in 1995, is a company whose primary purpose is to hold interests in energy-based businesses. The company conducts its business principally through Pacific Gas and Electric Company, or the Utility, a public utility operating in northern and central California. The Utility engages primarily in the businesses of electricity and natural gas distribution, electricity generation, procurement and transmission, and natural gas procurement, transportation and storage. PG&E Corporation became the holding company of the Utility and its subsidiaries on January 1, 1997. Both PG&E Corporation and the Utility are headquartered in San Francisco, California .

This is a combined quarterly report of PG&E Corporation and the Utility and includes separate Condensed Consolidated Financial Statements for each of these two entities. 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 the accounts of the Utility and its wholly owned and controlled subsidiaries and a variable interest entity which the Utility is required to consolidate under applicable accounting standards. This combined Management's Discussion and Analysis of Financial Condition and Results of Operations, or MD&A, of PG&E Corporation and the Utility should be read in conjunction with these Condensed Consolidated Financial Statements and Notes to the Condensed Consolidated Financial Statements, as well as the MD&A, Consolidated Financial Statements and Notes to the Consolidated Financial Statements incorporated by reference into their joint Annual Report on Form 10-K for the year ended December 31, 2005 filed with the Securities and Exchange Commission, or SEC. PG&E Corporation’s and the Utility’s combined Annual Report on Form 10-K for the year ended December 31, 2005, together with the information incorporated by reference into such report, is referred to in this quarterly report as the “2005 Annual Report.”

The Utility served approximately 5.0 million electricity distribution customers and approximately 4.2 million natural gas distribution customers at June 30, 2006. The Utility had approximately $33.7 billion in assets at June 30, 2006 and generated revenues of approximately $6.2 billion in the six months ended June 30, 2006.

The Utility is regulated primarily by the California Public Utilities Commission, or CPUC, and the Federal Energy Regulatory Commission, or FERC. The Utility's revenues are generated mainly through the sale and delivery of electricity and natural gas at rates set by the CPUC and the FERC. Rates are set to permit the Utility to recover its authorized “ revenue requirements ” from customers. Revenue requirements are designed to allow the Utility an opportunity to recover its reasonable costs of providing utility services, including a return of, and a fair rate of return on, its investment in utility facilities, or rate base. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues. Pending regulatory proceedings that could result in rate changes and affect the Utility's revenues are discussed in the 2005 Annual Report. Significant developments that have occurred since the 2005 Annual Report was filed with the SEC are discussed in this report.

Summary of Changes in Earnings per Common Share and Net Income for the Three and Six Months Ended June 30, 2006

PG&E Corporation’s diluted earnings per common share, or EPS, for the three and six months ended June 30, 2006 were $0.65 per share and $1.25 per share respectively, compared to the same periods in 2005 of $0.70 per share and $1.23 per share, respectively. The increase in diluted EPS for the six months ended June 30, 2006 primarily reflect a lower number of shares outstanding following the November 2005 share repurchase of 31,650,300 shares of PG&E Corporation common stock, the carrying cost credit associated with the second series of energy recovery bonds, or ERBs, issued in November 2005, and expenses associated with a scheduled refueling outage at the Utility’s Diablo Canyon nuclear power plant, or Diablo Canyon, that occurred in the second quarter of 2006. These three factors also affected diluted EPS for the three months ended June 30, 2006.

For the three and six months ended June 30, 2006, PG&E Corporation’s net income decreased, as expected, by $35 million, or 13%, and by $39 million, or 8%, respectively, compared to the same periods in 2005. As described below, the Utility provides a carrying cost credit associated with the second series of ERBs issued in November 2005. The equity portion of this carrying cost credit reduced authorized revenues and decreased net income for the three and six months ended June 30, 2006 by approximately $14 million and $29 million , respectively, as compared to the same periods in 2005. During the three months ended June 30, 2006, there was a 39-day refueling outage at Diablo Canyon which increased the Utility’s operating and maintenance expenses in the three and six months ended June 30, 2006 and resulted in lower net income of approximately $24 million for both periods. There was no refueling outage in the first six months of 2005 and no refueling outage is scheduled for the remainder of 2006. The Utility does not expect the Diablo Canyon refueling outage that occurred in the second quarter to

have a significant effect on net income for the year ended December 31, 2006, as compared to the year ended December 31, 2005 when the single refueling outage occurred in the fourth quarter of 2005.

In addition, net income for the t hree and six months ended June 30, 2006, reflects an increase in t he estimated cost of environmental remediation and the positive impact of the recognition of certain net regulatory assets. The increase in the estimated cost of environmental remediation results from a change in the remediation standard applicable to the ongoing remediation efforts at the Utility's gas compressor station located near Hinkley, California that occurred during the second quarter. This increase in the estimated cost of remediation reduced net income by approximately $18 million for both periods. (See discussion in the section entitled "Environmental and Legal Matters" below.) The recognition in the second quarter of certain net regulatory assets associated with costs incurred by the Utility beginning in 1998 in its capacity as scheduling coordinator, or SC, for certain wholesale electricity transmission customers resulted in an increase to net income of approximately $22 million for both periods. (See the discussion in the section entitled "Regulatory Matters" below.)

Factors Affecting Financial Condition and Results of Operations

In addition to the changes affecting net income as described above, several factors have had, and are expected to continue to have, a significant impact on PG&E Corporation's and the Utility's financial condition and results of operations, including:

- *Issuance of Energy Recovery Bonds* - During 2005, PG&E Energy Recovery Funding LLC, a limited liability company wholly owned by the Utility, or PERF, issued two separate series of ERBs for an aggregate amount of approximately $2.7 billion. In February 2005, the proceeds of the first series of ERBs in the amount of $1.9 billion were used to refinance the after-tax portion of the settlement regulatory asset established by the settlement agreement entered into among PG&E Corporation, the Utility, and the CPUC to resolve the Utility's Chapter 11 proceeding, or the Settlement Agreement. From January 1, 2005 through the date of the refinancing the Utility earned approximately $12 million, after tax, on the after-tax settlement regulatory asset calculated at the Utility's authorized 11.22% return on equity, or ROE. The Utility's earnings after the refinancing no longer include an ROE on the settlement regulatory asset. The November 2005 issuance of the second series of ERBs in the amount of $844 million was used to pre-fund the Utility's tax liability that will be due as the Utility collects the dedicated rate component, or DRC, used to secure repayment of the first series of ERBs from its customers. Until these taxes are fully paid, the Utility provides customers a carrying cost credit. The equity portion of this carrying cost credit reduced the Utility's 2006 net income for the three and six months ended June 30, 2006 by approximately $14 million and $29 million, respectively, as compared to the same periods in 2005. The equity portion of this carrying cost credit is estimated to reduce the Utility's net income in 2006 and 2007 by approximately $56 million and $48 million. The equity portion of the carrying cost credit will decline each year over the term of the ERBs until the ERBs are fully repaid in 2012.

- *Improved Capital Structure* - In January 2005, the equity component of the Utility's capital structure reached 52%, the target specified in the Settlement Agreement. Since this allowed the Utility to restore dividends and repurchase shares held by PG&E Corporation, PG&E Corporation reinstated the payment of a regular quarterly dividend. For 2006, the CPUC has authorized the equity component of the Utility's capital structure to remain at 52% and has set a ROE for 2006 of 11.35%. The Utility has requested the CPUC to waive the requirement for the Utility to file a 2007 cost of capital application and maintain the Utility's currently authorized cost of capital and capital structure (see "Regulatory Matters" below).

- *Stock Repurchases* - On November 16, 2005, PG&E Corporation entered into an accelerated share repurchase arrangement, or ASR, with Goldman Sachs & Co., Inc., or GS&Co., under which PG&E Corporation repurchased a total of 31,650,300 shares of common stock. As discussed above, the share repurchase decreased the number of shares outstanding for purposes of calculating EPS for the three and six months ended June 30, 2006. In conjunction with obligations associated with the share forward component of the ASR, PG&E Corporation paid GS&Co. $114 million during the course of the agreement. PG&E Corporation has accounted for these payments as equity with the payments of the obligations resulting in a reduction to common shareholders' equity so the payments had no effect on net income. At June 30, 2006 PG&E Corporation has no remaining obligation under the ASR .

- *The Outcome of Regulatory Proceedings, Including the 2007 General Rate Case* - Various regulatory proceedings are pending at the FERC and the CPUC, including the Utility's 2007 General Rate Case, or GRC, which is pending at the CPUC to determine the amount of the Utility's authorized base revenues to be collected from customers for the period 2007 through 2009. In the GRC, after consideration of reductions in its original revenue requirement request, the Utility's current request increases its 2007 revenue requirements for its electric distribution and existing electric generation operations, and for its natural gas distribution operations by $359 million and $35 million, respectively, over the authorized 2006 revenue requirements. The Utility also has requested attrition increases for 2008 and 2009. Other parties have recommended lower amounts (see " Regulatory Matters " below).

- *The Success of the Utility's Strategy to Achieve Operational Excellence and Improved Customer Service* - During 2006, the Utility is continuing to undertake various initiatives under its Business Transformation program to implement changes to its business processes and systems in an effort to provide better, faster and more cost-effective service to its customers. The Utility aims to achieve these goals in a three to five-year period. The Utility's 2007 GRC application included a proposed mechanism to share with customers savings that may be achieved through implementation of these initiatives. In addition, the Utility's 2007 GRC application includes a proposal to replace the current incentive mechanism for reliability performance for the 2007-2009 period with a new customer service performance incentive mechanism. Under the proposal, the Utility would be rewarded or penalized up to $60 million per year to the extent that the Utility's actual performance exceeds or falls short of pre-set annual performance improvement targets over the 2007-2009 period (see "Regulatory Matters" below).

- *The Amount and Timing of Capital Expenditures* - The Utility has requested regulatory approval of various capital expenditures to fund (1) investments in transmission and distribution infrastructure needed to serve its customers (i.e., to extend the life of existing infrastructure, to replace existing infrastructure, and to add new infrastructure to meet load growth), and (2) investment in new long-term generation resources, as may be authorized by the CPUC in accordance with the Utility's long-term electricity procurement plan. The CPUC also has authorized the Utility to deploy its advanced metering infrastructure, or AMI, project and authorized the Utility to recover its estimated project cost of $1.7 billion, including $1.4 billion of estimated capital costs, in rates.

- *Proposed New Long-Term Generation Resources* - On April 11, 2006, the Utility filed an application with the CPUC seeking approval of seven agreements for new long-term electricity generation resource commitments, including four power purchase agreements and a letter of intent to execute a power purchase agreement that together would provide over 1,400 megawatts, or MW, of capacity to the Utility from new generation facilities that would be owned and operated by other parties. The remaining two contracts provide for the construction by third parties of two new power plants to be owned and operated by the Utility. One contract calls for the construction of a 657 MW power plant and the other contract calls for the construction of a 163 MW power plant at the Utility's Humboldt Bay facility. The Utility anticipates that the CPUC will issue its decision on the Utility's application by the end of the year. Assuming that the CPUC approves the agreements and that permitting and construction schedules are met, the new generation facilities are anticipated to begin delivering power to the grid during the 2009 through 2010 time-frame. In addition, on June 15, 2006, the CPUC approved the Utility's application to acquire and build a 530 MW power plant to be located in Contra Costa County, or Contra Costa Unit 8.

- *Chromium Litigation Settlement* - On April 21, 2006, the Utility paid approximately $295 million to settle most of the claims involving allegations that exposure to chromium at or near some of the Utility's natural gas compressor stations caused personal injuries, wrongful deaths, or other injuries, referred to as the Chromium Litigation (discussed in Note 11 of the Notes to the Condensed Consolidated Financial Statements). PG&E Corporation and the Utility had previously accrued $314 million for the settlement and they do not believe that the outcome of the remaining unresolved claims in the Chromium Litigation will have a material adverse effect on their future results of operations or financial condition.

Forward-Looking Statements

This combined Quarterly Report on Form 10-Q, including the MD&A, contains forward-looking statements that are necessarily subject to various risks and uncertainties the realization or resolution of which are outside of management's control. These statements are based on current expectations and projections about future events, and assumptions regarding these events and management's knowledge of facts at the date of this report. These forward-looking statements relate to estimated capital expenditures, estimated Utility rate base, estimated environmental remediation liabilities, the anticipated outcome of various regulatory and legal proceedings, future cash flows, and the level of future equity issuances or share repurchases, and are also identified by words such as “assume,” “expect,” “intend,” “plan,” “project,” “believe,” “estimate,” “predict,” “anticipate,” “may,” “might,” “should,” “would,” “could,” “goal,” “potential” and similar expressions. PG&E Corporation’s and the Utility’s results of operations and financial condition depend primarily on whether the Utility is able to operate its business within authorized revenue requirements, timely recover its authorized costs, and earn its authorized rate of return. 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, are discussed in the section of the 2005 Annual Report entitled “Risk Factors.” These factors include, but are not limited to:

Operating Environment

- How the Utility manages its responsibility to procure electric capacity and energy for its customers, which can be affected by, among other factors, the extent to which the Utility's distribution customers are permitted to switch between purchasing electricity from the Utility or from alternate energy service providers as direct access customers or from cities, counties and others in the Utility's service territory as community choice aggregators, potentially resulting in stranded generating asset costs and non-recoverable procurement costs;

- The adequacy and price of natural gas supplies, and the ability of the Utility to manage and respond to the volatility of the natural gas market for its customers;

- Weather, storms, earthquakes, fires, floods, diseases, other natural disasters, explosions, accidents, mechanical breakdowns, acts of terrorism, and other events or hazards that affect demand for electricity or natural gas, result in power outages, reduce generating output, disrupt natural gas supply, cause damage to the Utility's assets or generating facilities, cause damage to the operations or assets of third parties on which the Utility relies, or subject the Utility to third party claims for damage or injury;

- Unanticipated population growth or decline, general economic and financial market conditions, changes in technology including the development of alternative energy sources, all of which may affect customer demand for natural gas or electricity;

- Whether the Utility is required to cease operations temporarily or permanently at Diablo Canyon, because the Utility is unable to increase its on-site spent nuclear fuel storage capacity, find another depositary for spent fuel, or timely complete the replacement of the steam generators, or because of mechanical breakdown, lack of nuclear fuel, environmental constraints, or for some other reason and the risk that the Utility may be required to purchase electricity from more expensive sources; and

- Whether the Utility is able to recognize the benefits expected to result from its efforts to improve customer service through implementation of specific initiatives to streamline business processes and deploy new technology such as its project to deploy an AMI.

Legislative Actions and Regulatory Proceedings

- The outcome of the regulatory proceedings pending at the CPUC and the FERC, including those discussed in “ Regulatory Matters ” below, and the impact of future ratemaking actions by the CPUC and the FERC;

- The impact of the recently enacted Energy Policy Act of 2005 which, among other provisions, repeals the Public Utility Holding Company Act of 1935 making electric utility industry consolidation more likely; expands the FERC’s authority to review proposed mergers; changes the FERC regulatory scheme applicable to qualifying facilities, or QFs; authorizes the formation of an Electric Reliability Organization to be overseen by the FERC to establish electric reliability standards; and modifies certain other aspects of energy regulation and federal tax policies applicable to the Utility;

- The extent to which the CPUC or the FERC delays or denies recovery of the Utility's costs, including electricity or gas purchase costs, from customers due to a regulatory determination that such costs were not reasonable or prudent, or for other reasons, resulting in write-offs of regulatory assets;

- How the CPUC administers the capital structure, stand-alone dividend, and first priority conditions of the CPUC's past decisions permitting the establishment of holding companies for the California investor-owned electric utilities and the outcome of the CPUC's new rulemaking proceeding concerning the relationship between the California investor-owned energy utilities and their holding companies and non-regulated affiliates, which may include (1) establishing reporting requirements for the allocation of capital between utilities and their non-regulated affiliates by the parent holding companies, and (2) changing the CPUC's affiliate transaction rules;

- Whether the Utility is determined to be in compliance with all applicable rules, regulations, tariffs and orders relating to electricity and natural gas utility operations, including tariffs related to the Utility’s billing and collection practices as discussed below in “Regulatory Matters,” and the extent to which a finding of non-compliance could result in customer refunds, penalties or other non-recoverable expenses, such as has been recommended with respect to the CPUC’s investigation into the Utility’s billing and collection practices; and

- Whether the Utility is required to incur material costs or capital expenditures or curtail or cease operations at affected facilities, including the Utility’s natural gas compressor stations, to comply with existing and future environmental laws, regulations and policies.

Pending Litigation

- The outcome of pending litigation.

Municipalization and Bypass

- Continuing efforts by local public utilities to take over the Utility's distribution assets through exercise of their condemnation power or by duplication of the Utility's distribution assets or service, and other forms of municipalization that may result in stranded investment capital, decreased customer growth, loss of customer load and additional barriers to cost recovery.

See the section entitled “Risk Factors” in the 2005 Annual Report and Part II, Item 1A. Risk Factors, below, for further discussion of the more significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operations.

RESULTS OF OPERATIONS

The table below details certain items from the accompanying Condensed Consolidated Statements of Income for the three and six-month periods ended June 30, 2006 and 2005.

(in millions)	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Utility				
Electric operating revenues	$ 2,214	$ 1,780	$ 4,077	$ 3,439
Natural gas operating revenues	803	718	2,088	1,727
Total operating revenues	3,017	2,498	6,165	5,166
Cost of electricity	781	487	1,311	884
Cost of natural gas	368	347	1,241	967
Operating and maintenance	982	670	1,844	1,441
Depreciation, amortization and decommissioning	421	454	834	839
Total operating expenses	2,552	1,958	5,230	4,131
Operating income	465	540	935	1,035
Interest income	39	20	58	39
Interest expense	(157)	(124)	(303)	(278)
Other income, net [1]	21	2	24	4
Income before income taxes	368	438	714	800
Income tax provision	141	166	273	309
Income available for common stock	$ 227	$ 272	$ 441	$ 491
PG&E Corporation, Eliminations and Other [2]				
Operating revenues	$ -	$ -	$ -	$ -
Operating (gain) expenses	-	-	1	(5)
Operating income (loss)	-	-	(1)	5
Interest income	2	(4)	6	(2)
Interest expense	(7)	(7)	(15)	(14)
Other income (expense), net	7	(4)	4	(7)
Income (loss) before income taxes	2	(15)	(6)	(18)
Income tax benefit	(3)	(10)	(11)	(12)
Net income (loss)	$ 5	$ (5)	$ 5	$ (6)
Consolidated Total [2]				
Operating revenues	$ 3,017	$ 2,498	$ 6,165	$ 5,166
Operating expenses	2,552	1,958	5,231	4,126
Operating income	465	540	934	1,040
Interest income	41	16	64	37
Interest expense	(164)	(131)	(318)	(292)
Other income (expense), net [1]	28	(2)	28	(3)
Income before income taxes	370	423	708	782
Income tax provision	138	156	262	297
Net income	$ 232	$ 267	$ 446	$ 485

[1] Includes preferred stock dividend requirement as other expense.

[2] PG&E Corporation eliminates all intercompany transactions in consolidation.

Utility

Overview

Under cost-of-service ratemaking, the Utility's rates are determined based on its costs of service and a substantial portion of the Utility revenues are adjusted periodically through revenue balancing account mechanisms to reflect differences between actual sales or demand compared to forecasted sales or demand used in setting rates. These balancing account mechanisms also track differences between actual purchased power and natural gas procurement costs compared to the forecasted amounts used in setting rates. The CPUC and the FERC determine the amount of “revenue requirements” that the Utility is authorized to collect from its customers to recover the Utility's operating and capital costs and earn a fair return. Revenue requirements are primarily determined based on the Utility's forecast of future costs, including the costs of purchasing electricity and natural gas on behalf of the Utility's customers.

The Utility currently faces a certain level of volumetric risk for the portion of intrastate natural gas transmission capacity that is not subscribed under long-term contracts with fixed reservation charges to core customers or other long-term contract holders (see further discussion in the Natural Gas Transportation and Storage section in the section entitled “Risk Management Activities” of the 2005 Annual Report). In addition, the Utility faces some volumetric risk in collecting its full electric transmission revenue requirement authorized in its electric transmission business.

The Utility's primary base revenue requirement proceeding is the GRC filed with the CPUC. In the GRC, the CPUC authorizes the Utility to collect from customers an amount known as base revenues to recover basic business and operational costs related to the Utility's electricity and natural gas distribution and electricity generation operations. The GRC typically sets annual revenue requirement levels for a three-year rate period. The CPUC authorizes these revenue requirements in GRC proceedings based on a forecast of costs for the first, or test, year. In the past, the CPUC has authorized future revenue requirement adjustments (attrition adjustments) in the second and third year of the GRC cycle. In addition, the CPUC generally conducts an annual cost of capital proceeding to determine the Utility's authorized capital structure and the authorized rate of return that the Utility may earn on its electricity and natural gas distribution and electricity generation assets. The cost of capital proceeding establishes the percentage components that common equity, preferred equity and debt will represent in the Utility's total authorized capital structure for a specific year. The CPUC then establishes the authorized return on common equity, preferred equity and debt that the Utility will collect in its authorized rates. The CPUC also has established ratemaking mechanisms to permit the Utility to timely recover its costs to procure electricity and natural gas on behalf of its customers in the energy markets.

The Utility's electricity and natural gas distribution and electric generation rates reflect the sum of individual revenue requirement components authorized by the CPUC. Changes in any individual revenue requirement affect customers' rates and could affect the Utility's revenues. Pending regulatory proceedings that could result in rate changes and affect the Utility's revenues are discussed in the section entitled “ Regulatory Matters ” in the 2005 Annual Report. Developments that have occurred in significant regulatory proceedings discussed in the 2005 Annual Report and significant new regulatory matters that have been initiated since the 2005 Annual Report was filed with the SEC are discussed below in the section entitled “Regulatory Matters.” Each year the Utility requests the CPUC to authorize an adjustment to electric and gas rates effective on the first day of the following year to (1) reflect over- and under-collections in the Utility's major electric and gas balancing accounts, and (2) consolidate various other electricity and gas revenue requirement changes authorized by the CPUC or the FERC. Balances in all accounts authorized for recovery are subject to review, verification and adjustment, if necessary, by the CPUC.

The timing of the CPUC and other regulatory decisions affect when the Utility is able to record the authorized revenues. In the 2007 GRC, the Utility requested the CPUC to approve an increase in 2007 electric and gas revenue requirements over the amount authorized for 2006 in the last GRC, as discussed below. The Utility has requested the CPUC to issue a decision in the 2007 GRC before the end of 2006 so the Utility can begin to record any authorized changes to revenues on January 1, 2007. The Utility has also requested attrition adjustments for 2008 and 2009. Further, the Utility has requested that the CPUC waive the requirement for the Utility to file a cost of capital application for 2007 and allow the Utility to maintain the Utility’s 2006 authorized cost of capital and capital structure.

Electric Operating Revenues

The Utility’s electricity rates are determined based on its cost of service. Differences between the authorized revenue requirements and amounts collected by the Utility from customers in rates are tracked in regulatory balancing accounts and are reflected in miscellaneous revenues in the table below.

In addition to electricity provided by the Utility's own generation facilities and electricity provided under the Utility's power purchase agreements with third-party providers, the Utility relies on electricity provided under long-term electricity procurement contracts entered into in 2001 through September 2005 with the California Department of Water Resources, or the DWR, to meet a material portion of its customers' demand. Revenues collected on behalf of the DWR and the DWR's related costs are not included in the Utility's Condensed Consolidated Statements of Income, reflecting the Utility's role as a billing and collection agent for the DWR's sales to the Utility's customers. Changes in the DWR's revenue requirements will not affect the Utility's revenues.

The Utility is required to dispatch, or schedule, all of the electricity resources within its portfolio, including electricity provided under the DWR allocated contracts, in the most cost-effective way. This requirement, in certain cases, requires the Utility to schedule more electricity than is necessary to meet its retail load and to sell this additional electricity on the open market. The Utility typically schedules excess electricity when the expected sales proceeds exceed the variable costs to operate a generation facility or buy electricity under an optional contract. Proceeds from the sale of surplus electricity are allocated between the Utility and the DWR based on the percentage of volume supplied by each entity to the Utility's total load. The Utility's net proceeds from the sale of surplus electricity after deducting the portion allocated to the DWR are recorded as a reduction to the cost of electricity.

The following table provides a summary of the Utility's electric operating revenues:

(in millions)	**Three Months Ended June 30,**		**Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Electric revenues	$ 2,514	$ 2,223	$ 4,753	$ 4,307
DWR pass-through revenue	(474)	(388)	(987)	(834)
Subtotal	2,040	1,835	3,766	3,473
Miscellaneous	174	(55)	311	(34)
Total electric operating revenues	$ 2,214	$ 1,780	$ 4,077	$ 3,439
Total electricity sales (in GWh) [1]	19,971	19,232	39,885	38,266

[1] Includes DWR electricity sales.

For the three months ended June 30, 2006, the Utility's electric operating revenues increased by approximately $434 million, or 24%, compared to the same period in 2005 mainly due to the following factors:

- Higher electricity procurement costs, which are passed through to customers, increased electric operating revenues by approximately $320 million due to increased volume of purchased power, hedging costs and a 39-day outage at Diablo Canyon which required the Utility to purchase higher-cost replacement power with no similar outage in the same period in 2005;

- On June 15, 2006, the CPUC approved the settlement reached among the Utility, the Division of Ratepayer Advocates, or DRA, and the Coalition of California Utility Employees that permits the Utility to recover revenue requirements attributable to pension contributions for its GRC lines of business. As a result, the Utility recorded approximately $60 million in electric revenues related to the three months ended June 30, 2006 in the second quarter of 2006 (refer to "Regulatory Matters" of this MD&A for further discussion of the pension settlement);

- Attrition adjustments, as authorized in the 2003 GRC, in which the CPUC approved the minimum and maximum yearly adjustments to the Utility's 2003 base revenue requirements, increased electric operating revenues by approximately $30 million;

- The DRC charge related to the ERBs increased electric operating revenues by approximately $30 million (see further discussion in Notes 3 and 4 of the Notes to the Condensed Consolidated Financial Statements). During the second quarter of 2005, the Utility collected the DRC for the first series of ERBs that were issued on February 10, 2005. During the second quarter of 2006, the Utility collected the DRC associated with the first series of ERBs in addition to the DRC related to the second series of ERBs, issued on November 9, 2005;

- Higher transmission revenues, including an increase in revenues as authorized in the FERC transmission rate case (refer to "Regulatory Matters" of this MD&A for further discussion of the FERC transmission rate case), increased electric operating revenues by approximately $35 million; and

- Miscellaneous other electric operating revenues increased by approximately $30 million.

The above increases were offset by the following decrease to electric operating revenues:

- The carrying cost credit, including both the debt and equity components, associated with the issuance of the second series of ERBs decreased electric operating revenues by approximately $75 million. The second series of ERBs was issued to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC related to the first series from its customers over the term of the ERBs. Until these taxes are fully paid, the Utility provides customers a carrying cost credit, computed at the Utility's authorized rate of return on rate base, to compensate them for the use of proceeds from the second series of ERBs as well as the after-tax proceeds of energy supplier refunds used to reduce the size of the second series of ERBs (see further discussion in the section entitled "Regulatory Matters" in the 2005 Annual Report).

For the six months ended June 30, 2006, the Utility’s electric operating revenues increased by approximately $638 million, or 19%, compared to the same period in 2005 mainly due to the following factors:

- Higher electricity procurement costs, which are passed through to customers, increased electric operating revenues by approximately $445 million due to increased volume and average cost of purchased power over the six months ended June 30, 2006, hedging costs and a 39-day outage at Diablo Canyon which required the Utility to purchase higher-cost replacement power with no similar outage in the same period in 2005;

- The DRC charge related to the ERBs increased electric operating revenues by approximately $115 million (see further discussion in Notes 3 and 4 of the Notes to the Condensed Consolidated Financial Statements). During the first six months of 2005, the Utility collected the DRC for the first series of ERBs that were issued on February 10, 2005. During the first six months of 2006, the Utility collected the DRC associated with the first series of ERBs in addition to the DRC related to the second series of ERBs, issued on November 9, 2005;

- Attrition adjustments, as authorized in the 2003 GRC, in which the CPUC approved the minimum and maximum yearly adjustments to the Utility's 2003 base revenue requirements, increased electric operating revenues by approximately $65 million;

- On June 15, 2006, the CPUC approved the settlement reached among the Utility, the DRA, and the Coalition of California Utility Employees that permits the Utility to recover revenue requirements attributable to pension contributions for its GRC lines of business. As a result, the Utility recorded approximately $60 million in electric revenues related to the six months ended June 30, 2006 in the second quarter of 2006. (Refer to "Regulatory Matters" of this MD&A for further discussion of the pension settlement);

- Higher transmission revenues, including an increase in revenues as authorized in the FERC transmission rate case (refer to "Regulatory Matters" of this MD&A for further discussion of the FERC transmission rate case), increased electric operating revenues by approximately $70 million; and

- Miscellaneous other electric operating revenues, including revenues associated primarily with public purpose programs and the CPUC authorization for the Self-Generation Incentive Plan, increased by approximately $50 million.

The above increases were offset by the following decreases to electric operating revenues:

- The carrying cost credit, including both the debt and equity components, associated with the issuance of the second series of ERBs decreased electric operating revenues by approximately $115 million. The second series of ERBs was issued to pre-fund the Utility's tax liability that will be due as the Utility collects the DRC related to the first series from its customers over the term of the ERBs. Until these taxes are fully paid, the Utility provides customers a carrying cost credit, computed at the Utility's authorized rate of return on rate base to compensate them for the use of proceeds from the second series of ERBs as well as the after-tax proceeds of energy supplier refunds used to reduce the size of the second series of ERBs (see further discussion in the section entitled "Regulatory Matters" in the 2005 Annual Report); and

- A decrease in the revenue requirement associated with the settlement regulatory asset (as discussed in further detail in the 2005 Annual Report) decreased electric operating revenues by approximately $55 million. As a result of the refinancing of the settlement regulatory asset on February 10, 2005 through issuance of the ERBs, the Utility was no longer authorized to collect this revenue requirement.

The Utility's electric operating revenues are expected to increase through the remainder of 2006 primarily due to higher electricity procurement costs, revenues associated with the pension settlement, and an attrition adjustment authorized in the 2003 GRC decision. Revenues for the period 2007 through 2009 would also increase to the extent authorized by the CPUC in the 2007 GRC and if the CPUC approves the Utility's proposed new long-term generation resource commitments (for further discussion see “2007 General Rate Case” and “Electricity Generation Resources” under “Regulatory Matters” of this MD&A). The CPUC also has authorized the Utility to deploy its AMI project and authorized the Utility to recover its estimated project cost of estimated capital costs in rates (for further discussion see the “Capital Expenditures” section of this MD&A). In addition, revenues associated with the collection of the DRC charge are scheduled to continue through 2012 when the ERBs mature.

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 the Utility's generation facilities, which are included in operating and maintenance expense. Electricity purchase costs and the cost of fuel used by owned generation facilities are passed through in rates to customers (see “Electric Operating Revenues” above for further details).

The following table provides a summary 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 June 30,**		**Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Cost of purchased power	$ 820	$ 575	$ 1,429	$ 1,029
Proceeds from surplus sales allocated to the Utility	(69)	(132)	(198)	(233)
Fuel used in own generation	30	44	80	88
Total cost of electricity	$ 781	$ 487	$ 1,311	$ 884
Average cost of purchased power per kWh	$ 0.080	$ 0.072	$ 0.078	$ 0.069
Total purchased power (GWh)	10,302	7,944	18,258	14,929

The Utility’s cost of electricity increased by approximately $294 million, or 60%, in the three months ended June 30, 2006 as compared to the same period in 2005 . Cost of purchased power, including hedging costs, increased by approximately $245 million, or 43%. This increase was primarily due to an increase in volume of approximately 2,358

Gigawatt-hours, or GWh, or 30%. The volume of total purchased power increased partly due to an increase in customer usage and a decrease in the volume of electricity provided by the DWR to the Utility's customers. The increase in the volume of purchase power is also due to a 39-day refueling outage at Diablo Canyon during the second quarter of 2006, which required the Utility to purchase higher-cost replacement power, as compared to the second quarter of 2005 when Diablo Canyon was in full operation and no such purchases were required. The average cost of purchased power increased by $0.008 per kilowatt hour, or kWh, or 11%.

The Utility’s cost of electricity increased by approximately $427 million, or 48%, in the six months ended June 30, 2006 as compared to the same period in 2005. Cost of purchased power, including hedging costs, increased by approximately $400 million, or 39%. The increase is due to an increase in volume of approximately 3,329 GWh, or 22%. The volume of total purchased power increased partly due to an increase in customer usage and a decrease in the volume of electricity provided by the DWR to the Utility's customers. The increase in the volume of purchase power is also due to a 39-day refueling outage at Diablo Canyon during the second quarter of 2006, which required the Utility to purchase higher-cost replacement power, as compared to the first six months of 2005 when Diablo Canyon was in full operation and no such purchases were required. The average cost of purchased power increased by $0.009 per kWh, or 13%.

The Utility's cost of electricity in 2006 will depend upon electricity prices and any change in customer usage which will directly impact the Utility's net open position (see the “ Risk Management Activities ” section of this MD&A). Cost of electricity is also dependent upon weather patterns and seasonality. The above-average rainfall in the first quarter of 2006 increased hydroelectric energy production for the first six months of 2006.

The Utility’s cost of electricity also may be affected by potential federal or state legislation or rules which may regulate the emissions of greenhouse gases from the Utility’s electric generating facilities or the generating facilities from which the Utility procures power. Currently, the CPUC is considering adopting by the end of 2006 a greenhouse gas emissions performance standard that would apply to electricity procured or generated by the Utility. Similarly, the California Legislature and Governor are considering two proposed bills, SB 1368 and AB 32, that would establish a greenhouse gas emissions performance standard and a greenhouse gas cap, respectively, applicable to the Utility’s emissions of greenhouse gases. Because the Utility’s existing and forecast emissions of greenhouse gases are relatively low compared to average emissions by other electric utilities and generators in the country, the proposed regulations being considered by the CPUC, the California Legislature and the California Governor are not expected to significantly affect the Utility’s overall cost of service, and any incremental costs of service are expected to be recovered in full in rates to the Utility’s customers under the CPUC’s ratemaking standards applicable to electricity procurement costs.

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation (transmission and distribution) services to its customers. The Utility's transportation system transports gas throughout California to the Utility's distribution system, which, in turn, delivers gas to end-use customers. The Utility's natural gas customers consist of two categories: core and non-core customers. The core customer class is comprised mainly of residential and smaller commercial natural gas customers. The non-core customer class is comprised of industrial and larger commercial natural gas customers. The Utility provides natural gas delivery services to all core and non-core customers connected to the Utility's system in its service territory. Core customers can purchase natural gas from alternate energy service providers or can elect to have the Utility provide both delivery service and natural gas supply.

The Utility's natural gas transmission and storage rates for the 2005 through 2007 period have been determined by a December 2004 CPUC decision which approved the Gas Accord III Settlement Agreement reached among the Utility and other interested parties. Under the Gas Accord III Settlement Agreement, the Utility agreed to not have a balancing account for the over-collections or under-collections of natural gas transmission or storage revenues, thus assuming the risk of not recovering its full natural gas transmission and storage costs that are not covered by long-term contracts with fixed reservation charges with its non-core customers or other customers (see discussion under “ Risk Management Activities - Natural Gas Transportation and Storage ” in the 2005 Annual Report). Under the terms of the Gas Accord III Settlement Agreement, the Utility will establish gas transmission and storage rates for 2008 (and possibly subsequent years) in its Gas Transmission and Storage 2008 Rate Case, which the Utility must file no later than February 9, 2007.

The Utility recovers the cost of gas (subject to the ratemaking mechanism discussed below), acquired on behalf of core procurement customers through its retail gas rates. The Utility is protected against after-the-fact reasonableness reviews of these gas procurement costs under an incentive mechanism known as the Core Procurement Incentive Mechanism, or CPIM. Under the CPIM, the Utility's purchase costs for a twelve month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natural gas price indices at the points where the Utility typically purchases natural gas. The CPIM establishes a “tolerance band” around the benchmark index price, and all costs within the tolerance band are fully recovered from core customers. If total gas costs fall below the tolerance band,

PG&E's customers and shareholders will share 75% and 25% of the savings below the tolerance band, respectively. Conversely, if total gas costs rise above the tolerance band, the Utility's core customers and shareholders share equally the costs above the tolerance band. The shareholder award is capped at the lower of 1.5% of total natural gas commodity costs or $25 million. While this incentive mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

On October 6, 2005, the CPUC approved the Utility's hedging plan for the winters of 2005-06, 2006-07, and 2007-08. Core customers will pay the cost of these hedges and receive any payouts as these transactions are handled outside of the CPIM. The Utility is at risk to the extent that the CPUC may disallow portions of the hedging cost based on its subsequent review of the Utility's performance under the filed plan. As part of the hedging plan, the Utility has also agreed to forego a shareholder award under the CPIM for the 2004-2005 CPIM year.

The following table provides a summary of the Utility's natural gas operating revenues:

(in millions)	**Three Months Ended June 30,**		**Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Bundled natural gas revenues	$ 734	$ 665	$ 1,951	$ 1,609
Transportation service-only revenues	69	53	137	118
Total natural gas operating revenues	$ 803	$ 718	$ 2,088	$ 1,727
Average bundled revenue per millions of Mcf of natural gas sold	$ 11.84	$ 11.33	$ 11.78	$ 9.68
Total bundled natural gas sales (in millions of Mcf)	62	59	166	167

The Utility's natural gas operating revenues increased by approximately $85 million, or 12%, during the three months ended June 30, 2006 compared to the same period in 2005. The increase in natural gas operating revenues was primarily due to the following factors:

- Excluding the impact of the 2003 GRC decision, revenue requirements associated with the pension settlement, and miscellaneous other natural gas operating revenues, bundled natural gas operating revenues increased by approximately $28 million, or 4%. This increase was primarily due to an increase in the cost of natural gas, including hedging costs, as further discussed below in "Cost of Natural Gas";

- Attrition adjustments, as authorized in the 2003 GRC, and revenues authorized in the 2006 cost of capital proceeding increased natural gas operating revenues by approximately $9 million;

- On June 15, 2006, the CPUC approved the settlement reached among the Utility, the DRA and the Coalition of California Utility Employees that will permit the Utility to recover revenue requirements attributable to pension contributions for its GRC lines of business. As a result, the Utility recorded approximately $21 million in natural gas revenues related to the three months ended June 30, 2006 in the second quarter of 2006;

- Miscellaneous and other natural gas revenues increased by approximately $11 million; and

- Transportation service-only revenues increased by approximately $16 million, or 30%, primarily as a result of an increase in rates.

The Utility's natural gas operating revenues increased by approximately $361 million, or 21%, during the six months ended June 30, 2006 compared to the same period in 2005. The increase in natural gas operating revenues was primarily due to the following factors:

- Excluding the impact of the 2003 GRC decision, revenue requirements associated with the pension settlement, and miscellaneous other natural gas operating revenues, bundled natural gas operating revenues increased by approximately $269 million, or 16%. This increase was primarily due to an increase in the cost of natural gas (primarily in the first quarter of 2006 compared to the first quarter of 2005), including hedging costs, as further discussed below in "Cost of Natural Gas";

- Attrition adjustments, as authorized in the 2003 GRC, and revenues authorized in the 2006 cost of capital proceeding increased natural gas operating revenues by approximately $18 million;

- On June 15, 2006, the CPUC approved the settlement reached among the Utility, the DRA and the Coalition of California Utility Employees that will permit the Utility to recover revenue requirements attributable to pension contributions for its GRC lines of business. As a result, the Utility recorded approximately $21 million in natural gas revenues related to the six months ended June 30, 2006 in the second quarter of 2006;

- Miscellaneous and other natural gas revenues increased by approximately $34 million; and

- Transportation service-only revenues increased by approximately $19 million, or 16%, primarily as a result of an increase in rates.

The Utility's natural gas revenues in 2006 are expected to increase due to an attrition rate increase authorized in the 2003 GRC decision, revenue requirements associated with the pension settlement, and an annual rate escalation authorized in the Gas Accord III Settlement, and will be further impacted by changes in the cost of natural gas.

Cost of Natural Gas

The Utility's cost of natural gas includes the purchase cost of natural gas and transportation costs on interstate pipelines, but excludes the costs associated with operating and maintaining the Utility's intrastate pipeline, which are included in operating and maintenance expense.

The following table provides a summary of the Utility's cost of natural gas:

(in millions)	**Three Months Ended June 30,**		**Six Months Ended June 30,**	
	2006	**2005**	**2006**	**2005**
Cost of natural gas sold	$ 333	$ 313	$ 1,170	$ 896
Cost of natural gas transportation	35	34	71	71
Total cost of natural gas	$ 368	$ 347	$ 1,241	$ 967
Average cost per millions of Mcf of natural gas sold	$ 5.37	$ 5.31	$ 7.05	$ 5.37
Total natural gas sold (in millions of Mcf)	62	59	166	167

The Utility's total cost of natural gas, including hedging costs, increased by approximately $21 million, or 6%, in the three months ended June 30, 2006 as compared to the same period in 2005. This increase was primarily due to an increase in volume of natural gas sold of approximately 3 million thousand cubic feet, or Mcf, or 5% and an increase in the average price of natural gas purchased over the three months ended June 30, 2006 of approximately $.06 per Mcf, or 1%.

The Utility's total cost of natural gas, including hedging costs, increased by approximately $274 million, or 28%, in the six months ended June 30, 2006 as compared to the same period in 2005. This increase was primarily due to an increase in the price of natural gas purchased in the first three months of 2006. The average price of natural gas purchased over the six months ended June 30, 2006 increased by approximately $1.68 per Mcf, or 31%.

The Utility's cost of natural gas sold in 2006 will be primarily affected by the prevailing costs of natural gas, which are determined by North American regions that supply the Utility. In October 2005, the CPUC granted the Utility authority to execute hedges on behalf of the Utility's core gas customers, and to record the costs and any payouts of such hedges in a separate balancing account, outside of CPIM. This action was undertaken because of rapidly rising natural gas prices in the wake of Hurricanes Katrina and Rita. The CPUC's decision authorizes enhanced hedging activity on behalf of core customers for the winter of 2005 through 2006 and for two subsequent winters. The Utility has agreed to forego a shareholder award for the CPIM year ending October 31, 2005 (for further discussion see “Risk Management” section of the MD&A in the 2005 Annual Report). More recently, the Utility also has requested additional hedging authority from the CPUC for the winter for 2006-2007, and that request is pending at this time. If this new request is approved by the CPUC, the Utility will be able to hedge a substantial percentage of its winter gas purchases on behalf of core customers. The cost of gas will also be affected by customer demand.

Operating and Maintenance

Operating and maintenance expenses consist mainly of the Utility's costs to operate and maintain its electricity and natural gas facilities, customer accounts and service expenses, public purpose program expenses, and administrative and general expenses. Generally, many of these expenses are offset by corresponding annual revenues authorized by the CPUC in various rate proceedings to be collected from customers.

During the three months ended June 30, 2006, the Utility’s operating and maintenance expenses increased by approximately $312 million, or 47%, compared to the same period in 2005, mainly due to the following factors:

- An increase of approximately $115 million primarily due to the funding of the pension plan as a result of the CPUC-approved settlement (refer to "Regulatory Matters" of this MD&A for further discussion of the pension settlement) ;
- An increase of approximately $40 million reflecting costs associated with the scheduled Diablo Canyon refueling outage in the second quarter of 2006;
- An increase of approximately $30 million due to a reassessment of the estimated cost of environmental remediation related to the Hinkley gas compressor station (refer to “Environmental and Legal Matters” of this MD&A for further discussion);
- An increase of approximately $20 million related to administrative and general salary expenses reflecting the increased costs associated with base salaries and incentives;
- An increase of approximately $20 million related to administrative expenses for low-income customer assistance programs, the Self-Generation Incentive Program, AMI and community outreach programs; and
- An increase of approximately $15 million related to outside consulting, contract expense, and various programs and initiatives including strategies to achieve operational excellence and improved customer service.

During the six months ended June 30, 2006, the Utility’s operating and maintenance expenses increased by approximately $403 million, or 28%, compared to the same period in 2005, mainly due to the following factors:

- An increase of approximately $125 million primarily due to the funding of the pension plan as a result of the CPUC-approved settlement (refer to "Regulatory Matters" of this MD&A for further discussion of the pension settlement);
- An increase of approximately $60 million related to administrative and general salary expenses reflecting increased costs associated with base salaries and incentives;
- An increase of approximately $50 million related to administrative expenses for low-income customer assistance programs, the Self-Generation Incentive Program, AMI, and community outreach programs;
- An increase of approximately $40 million reflecting costs associated with the scheduled Diablo Canyon refueling outage in the second quarter of 2006; and
- An increase of approximately $20 million related to outside consulting, contract expense, and various programs and initiatives including strategies to achieve operational excellence and improved customer service.

The Utility’s operating and maintenance expenses in 2006 are expected to increase as a result of increased expenses related to various programs and initiatives, including public purpose programs and strategies to achieve operational excellence and improved customer service (see “Overview” section in this MD&A for further discussion). In connection with the Utility’s continued effort to streamline processes and focus on the customer, jobs from numerous locations around California are being consolidated and t he Utility is anticipating a workforce reduction. Therefore, severance costs may have a future impact of up to approximately $55 million on operating and maintenance expenses based on costs under a pre

-existing severance plan (see further discussion in Note 11 of the Notes to the Condensed Consolidated Financial Statements). Operating and maintenance expenses are influenced by wage inflation, benefits, property taxes, the timing and length of Diablo Canyon refueling outages, environmental remediation costs, legal costs and various other administrative and general expenses.

Depreciation, Amortization and Decommissioning

The Utility charges the original cost of retired plant less salvage value to accumulated depreciation upon retirement of plant in service for its lines of business that apply Statement of Financial Accounting Standards, or SFAS, No. 71, " Accounting for the Effects of Certain Types of Regulation, " as amended, which includes electricity and natural gas distribution, electricity generation and transmission, and natural gas transportation and storage.

In the three months ended June 30, 2006, the Utility's depreciation, amortization and decommissioning expenses decreased by $33 million, or 7%, compared to the same period in 2005, primarily as a result of the decrease in amortization of the settlement regulatory asset resulting from the refinancing of the settlement regulatory asset by the issuance of the first series of ERBs. The Utility recorded approximately $43 million in the three months ended June 30, 2005 for amortization of the settlement regulatory asset, with no similar amount in 2006.

This decrease is partially offset by an increase in the amortization of the ERB regulatory asset of approximately $14 million. During the second quarter of 2006, the Utility continued to amortize the ERB regulatory assets for the first series of ERBs issued in February 2005, as well as the second series of ERBs, issued in November 2005.

In the six months ended June 30, 2006, the Utility's depreciation, amortization and decommissioning expenses decreased by $5 million, or 1%, compared to the same period in 2005, primarily as a result of the decrease in amortization of the settlement regulatory asset resulting from the refinancing of the settlement regulatory asset by the issuance of the first series of ERBs. The Utility recorded approximately $76 million in the six months ended June 30, 2005 for amortization of the settlement regulatory asset, with no similar amount in 2006. In addition, the Utility recorded approximately $15 million in depreciation expense in the six months ended June 30, 2005 related to recovery of costs as authorized in a December 2004 settlement agreement between the Utility, ORA, Aglet Consumer Alliance and The Utility Reform Network, or TURN. Under the settlement agreement the Utility was authorized to collect revenue requirements to recover the capital plant costs associated with distribution related electric industry restructuring costs through rates in 2005. There was no similar depreciation expense in 2006.

This decrease is partially offset by an increase in the amortization of the ERB regulatory asset by approximately $88 million. During the second six months of 2006, the Utility amortized the ERB regulatory assets for the first series of ERBs as well as the second series of ERBs. In addition, it was offset by an increase in depreciation expense.

The Utility's depreciation, amortization and decommissioning expenses in 2006 are expected to increase as a result of an overall increase in assets due to higher capital expenditures.

Interest Income

In the three months ended June 30, 2006, interest income increased by approximately $19 million, or 95%, compared to the same period in 2005. In the six months ended June 30, 2006, interest income increased by approximately $19 million, or 49%, compared to the same period in 2005. Increases for both periods were a result of the Utility recording $20 million of interest income due to the net regulatory asset associated with the scheduling coordinator costs. (See "Regulatory Matters" below for further discussion). This increase was partially offset by a decrease in interest earned on short-term investments.

The Utility's interest income during 2006 will be primarily affected by interest rate levels.

Interest Expense

In the three months ended June 30, 2006, the Utility's interest expense increased by approximately $33 million, or 27%, compared to the same period in 2005. The increase was primarily due to a portion of the interest expense in 2005 relating to energy supplier claims that were not recorded for recovery until the second quarter of 2005, retroactive to the issuance date of the first series of ERBs. The applicable tariff provides that reasonable net interest costs on energy supplier claims subsequent to the issuance of the ERBs may be recovered (see the "Regulatory Matters" section of the MD&A in the 2005 Annual Report). Additionally, a portion of the increase is due to the over-collected position of certain revenue balancing accounts combined with an increase in the interest rates associated with these accounts.

In the six months ended June 30, 2006, the Utility's interest expense increased by approximately $25 million, or 9%, compared to the same period in 2005. The increase is primarily due to interest expense associated with the ERBs which was not incurred until after issuance of each series of bonds in 2005, resulting in interest being recorded for only a portion of the six months in 2005 for the first series of ERBs, as compared to interest being recorded for both the first and second series of ERBs for the six month period in 2006. Additionally, a portion of the increase is due to the over-collected position of certain revenue balancing accounts combined with an increase in the interest rates associated with these accounts.

The Utility's interest expense in 2006 and subsequent periods is expected to increase if interest rates continue to rise as the Utility's short-term debt and a portion of its long-term debt are interest rate-sensitive and due to higher expected financing resulting from an overall increase in infrastructure investments.

Income Tax Expense

In the three months ended June 30, 2006, the Utility's tax expense decreased approximately $25 million, or 15%, compared to the same period in 2005, primarily due to the decrease in pre-tax income of $70 million for the three months ended June 30, 2006. The effective tax rate for the three months ended June 30, 2006 decreased by 0.3 percentage points from the same period in 2005.

In the six months ended June 30, 2006, the Utility's tax expense decreased approximately $36 million, or 12%, compared to the same period in 2005, primarily due to the decrease in pre-tax income of $87 million for the six months ended June 30, 2006. The effective tax rate for the six months ended June 30, 2006 decreased by 0.4 percentage points from the same period in 2005.

PG&E Corporation, Eliminations and Other

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to the Utility and its other 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 its affiliates. Operating expenses are allocated to affiliates without mark-up and are eliminated in consolidation. For the three and six months ended June 30, 2006, there were no material changes to PG&E Corporation's operating income (loss).

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The level of PG&E Corporation's and the Utility's current assets and current liabilities is subject to fluctuation as a result of seasonal demand for electricity and natural gas, energy commodity costs, and the timing and effect of regulatory decisions and financings, among other factors.

PG&E Corporation and the Utility manage liquidity and debt levels in order to meet expected operating and financial needs and maintain access to credit for contingencies. PG&E Corporation and the Utility intend to manage the Utility's equity level to maintain the Utility's 52% authorized common equity ratio of the Utility's capital structure.

At June 30, 2006, PG&E Corporation and its subsidiaries had consolidated cash and cash equivalents of approximately $421 million and restricted cash of approximately $1.5 billion. PG&E Corporation and the Utility maintain separate bank accounts. At June 30, 2006, PG&E Corporation on a stand-alone basis had cash and cash equivalents of approximately $256 million; the Utility had cash and cash equivalents of approximately $165 million, and restricted cash of approximately $1.5 billion. The Utility's restricted cash includes amounts deposited in escrow related to the remaining disputed Chapter 11 claims and deposits under certain third-party agreements. PG&E Corporation and the Utility primarily invest their cash in money market funds and in short-term obligations of the U.S. government and its agencies.

As of June 30, 2006, PG&E Corporation and the Utility had credit facilities totaling $200 million and $2 billion, respectively, with remaining borrowing capacity under these credit facilities of $200 million and $1.6 billion, respectively. In January 2006, the Utility established a $1 billion commercial paper program. At June 30, 2006, the Utility had $213 million of outstanding borrowings under the commercial paper program.

On June 15, 2006, the CPUC approved the Utility's financing application for issuance of up to $3 billion of long-term debt or preferred stock to meet ongoing capital spending requirements, replace maturing debt, and redeem debt and preferred stock.

During the six months ended June 30, 2006, the Utility used cash in excess of amounts needed for operations, debt service, capital expenditures, and preferred stock requirements to pay quarterly common stock dividends.

Depending on the timing and amount of capital expenditures and liquidity needs, PG&E Corporation may use cash available after capital expenditures and dividends to repurchase shares using cash distributions received from the Utility, and cash available from option exercises. PG&E Corporation anticipates that, over the next five years, it may issue shares (possibly through a combination of employee plans and direct issuance to the market) and contribute the proceeds to the Utility, to fund capital expenditures in years of higher capital expenditures, while it may repurchase shares in years with lower capital expenditures. Over the five-year period, these share issuances and repurchases are expected to approximately offset each other and result in no net issuance of equity.

Dividends

On April 17, 2006, PG&E Corporation paid a common stock dividend of $0.33 per share, or approximately $114 million total, to shareholders of record on March 31, 2006. On February 16, 2006, the Utility paid a common stock dividend in the aggregate amount of $124 million, which is consistent with the dividend target. Approximately $115 million of the common stock dividend was paid to PG&E Corporation and the remainder was paid to PG&E Holdings, LLC, a wholly owned subsidiary of the Utility.

On June 21, 2006, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.33 per share, or approximately $115 million total, payable on July 15, 2006 to shareholders of record on July 3, 2006. On June 22, 2006, the Utility paid a common stock dividend in the aggregate amount of $124 million, which is consistent with the dividend target. Approximately $115 million of the common stock dividend was paid to PG&E Corporation and the remainder was paid to PG&E Holdings, LLC. PG&E Corporation and the Utility recorded common stock dividends declared to Reinvested Earnings.

On February 15 and May 15, 2006, the Utility paid a cash dividend on various series of its preferred stock, totaling approximately $7 million. On June 21, 2006, the Board of Directors of the Utility declared a cash dividend on various series of its preferred stock payable on August 15, 2006, to shareholders of record on July 31, 2006.

Stock Repurchases

On March 28, 2006, the obligations of PG&E Corporation and GS&Co. with respect to the share forward agreement related to the November 16, 2005 ASR (under which PG&E Corporation repurchased and retired 31,650,300 shares of its outstanding common stock) was terminated in accordance with its terms as a result of a declaration of the PG&E Corporation common stock dividend payable on April 15, 2006. In connection with the termination, on March 31, 2006, PG&E Corporation paid GS&Co. approximately $58 million (net of amounts payable by GS&Co. to PG&E Corporation), including a price adjustment based on the average of the daily volume weighted average price, or VWAP, of PG&E Corporation common stock from November 17, 2005 through March 28, 2006.

On March 28, 2006, PG&E Corporation entered into a new share forward agreement with GS&Co. to complete the ASR. The March 28, 2006 share forward agreement was terminated in accordance with its terms on June 8, 2006. In connection with the termination, on June 13, 2006, PG&E Corporation paid GS&Co. approximately $56 million (net of amounts payable by GS&Co. to PG&E Corporation), including a price adjustment based on the difference between $34.75 per share, and the average of the VWAP of PG&E Corporation common stock from March 29, 2006 through June 8, 2006. PG&E Corporation has no remaining obligation under the ASR.

For further discussion, see Note 5 of the Notes to the Condensed Consolidated Financial Statements.

Utility

Operating Activities

The Utility's cash flows from operating activities consist of sales to its customers and payments of operating expenses, other than expenses such as depreciation that do not require the use of cash. Cash flows from operating activities are also impacted by collections of accounts receivable and payments of liabilities previously recorded.

The Utility's cash flows from operating activities for the six months ended June 30, 2006 and 2005 were as follows:

(in millions)	**Six Months Ended June 30,**	
	2006	**2005**
Net income	$ 448	$ 499
Non-cash (income) expenses:		
Depreciation, amortization, decommissioning and allowance for equity funds used during construction	867	839
Deferred income taxes and tax credits, net	73	(103)
Other deferred charges and noncurrent liabilities	153	(83)
Gain on sale of assets	(15)	(1)
Change in accounts receivable	373	56
Change in accrued taxes	(110)	188
Change in regulatory balancing accounts, net	18	565
Other changes in operating assets and liabilities	(297)	(356)
Net cash provided by operating activities	$ 1,510	$ 1,604

Net cash provided by operating activities decreased by approximately $94 million during the six months ended June 30, 2006 compared to the same period in 2005. This is primarily due to payments in 2006 of approximately $320 million for litigation settlements, including the Chromium Litigation settlement agreement.

The above decrease was offset by the receipt of cash proceeds associated with settlements with energy suppliers of approximately $273 million during the six months ended June 30, 2006 (see Note 11 of the Notes to the Condensed Consolidated Financial Statements for further discussion).

In November 2005, the CPUC approved an initiative to help consumers manage high natural gas bills in the winter. The 10/20 Winter Gas Savings Program was a conservation incentive that offered residential and small business customers a 20 percent rebate for reducing their gas usage by 10 percent or more this winter, January through March 2006. The Utility issued approximately $42 million in rebates to customers from March through June 2006. As a result, the Utility’s cash inflows are lower for the three months ended June 30, 2006 as compared to the three months ended June 30, 2005. The Utility has recovered these rebates through rates during April through July 2006.

Investing Activities

The Utility's investing activities consist of construction of new and replacement facilities necessary to deliver safe and reliable electricity and natural gas services to its customers. Cash flows from operating activities have been sufficient to fund the Utility's capital expenditure requirements during the six months ended June 30, 2006 and 2005. Year-to-year variances depend upon the amount and type of construction activities, which can be influenced by storms and other factors.

The Utility's cash flows from investing activities for the six months ended June 30, 2006 and 2005 were as follows:

(in millions)	**Six Months Ended June 30,**	
	2006	**2005**
Capital expenditures	$ (1,178)	$ (803)
Net proceeds from sale of assets	7	17
Decrease in restricted cash	48	321
Proceeds from nuclear decommissioning trust sales	757	2,008

Purchases of nuclear decommissioning trust investments	(799)	(2,038)
Other investing activities	-	42

Net cash used in investing activities	$ (1,165)	$ (453)

Net cash used by investing activities increased by approximately $712 million primarily due to an increase in capital expenditures of approximately $375 million for the six months ended June 30, 2006. The Utility estimates that in July through December of 2006 it will invest an additional $1.4 billion in plant and equipment (see "Capital Expenditures" section in this MD&A for further discussion). In addition, the decrease in restricted cash was approximately $273 million greater in the six months ended June 30, 2005, than in the same period in 2006 due to more releases of escrow funds related to supplier settlements.

Financing Activities

The Utility's cash flows from financing activities for the six months ended June 30, 2006 and 2005 were as follows:

(in millions)	**Six Months Ended June 30,**	
	2006	**2005**
Borrowings under accounts receivable facility	$ 50	$ -
Repayments under working capital facility and accounts receivable facility	(310)	(300)
Borrowings under commercial paper facility, net	213	-
Proceeds from issuance of long-term debt	-	451
Net proceeds from energy recovery bonds issued	-	1,874
Long-term debt, matured, redeemed or repurchased	-	(1,354)
Rate reduction bonds matured	(141)	(141)
Energy recovery bonds matured	(130)	(14)
Common stock dividends paid	(230)	(220)
Preferred stock dividends paid	(7)	(8)
Preferred stock with mandatory redemption provisions redeemed	-	(122)
Common stock repurchased	-	(960)
Other financing activities	(88)	-
Net cash used in financing activities	$ (643)	$ (794)

For the six months ended June 30, 2006, net cash used in financing activities decreased by approximately $151 million compared to the same period in 2005, primarily due to the following factors:

- The Utility had net borrowings of $213 million of commercial paper, with no similar amount in 2005;
- In May 2005, the Utility entered into seven loan agreements with the California Infrastructure and Economic Development Bank under which the Utility borrowed $451 million funded by the bank's issuance of Pollution Control Bonds Series A-G with no similar borrowing in 2006;
- In February 2005, PERF issued approximately $1.9 billion of ERBs with no similar issuance in 2006. In March 2005, the Utility used proceeds from the issuance of ERBs to repurchase $960 million of its common stock from PG&E Corporation, with no similar repurchase in 2006;
- Approximately $130 million of ERBs matured in the first and second quarters of 2006, with no similar maturities in the first quarter of 2005 and only $14 million of maturities in the second quarter of 2005;
- During the six months ended June 30, 2005, the Utility fully redeemed $122 million of preferred stock with mandatory redemption provisions, with no similar redemption in 2006; and

- In January 2005, the Utility partially redeemed Floating Rate First Mortgage Bonds due in 2006 in the aggregate principal amount of $300 million, and in February 2005, the Utility used a portion of the ERB proceeds to defease $600 million of Floating Rate First Mortgage Bonds. In April 2005, the Utility repaid $454 million under certain reimbursement obligations that the Utility entered into in April 2004, when its plan of reorganization under Chapter 11 became effective. There were no similar redemptions and repayments in 2006.

PG&E Corporation

As of June 30, 2006, PG&E Corporation had stand-alone cash and cash equivalents of approximately $256 million. PG&E Corporation's sources of funds are dividends and share repurchases from the Utility, issuance of its common stock and external financing.

Operating Activities

PG&E Corporation's consolidated cash flows from operating activities consist mainly of billings to the Utility and other 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, on a stand alone basis, did not have any material operating activities for the six months ended June 30, 2006 and 2005.

Investing Activities

PG&E Corporation, on a stand alone basis, did not have any material investing activities for the six months ended June 30, 2006 and 2005.

Financing Activities

PG&E Corporation's consolidated cash flows from financing activities consist mainly of cash generated from debt financing, issuance of common stock, and the payment of dividends.

PG&E Corporation's consolidated cash flows from financing activities for the six months ended June 30, 2006 and 2005 were as follows:

(in millions)	**Six Months Ended June 30,**	
	2006	**2005**
Borrowings under accounts receivable facility	$ 50	$ -
Repayments under working capital facility and accounts receivable facility	(310)	(300)
Borrowings under commercial paper facility, net	213	-
Net proceeds from issuance of energy recovery bonds	-	1,874
Proceeds from issuance of long-term debt	-	451
Long-term debt matured, redeemed or repurchased	-	(1,356)
Rate reduction bonds matured	(141)	(141)
Energy recovery bonds matured	(130)	(14)
Preferred stock with mandatory redemption provisions redeemed	-	(122)
Common stock issued	77	190
Common stock repurchased	(114)	(1,065)
Common stock dividends paid	(228)	(111)
Other	(84)	(14)
Net cash used by financing activities	$ (667)	$ (608)

For the six months ended June 30, 2006 PG&E Corporation's consolidated net cash used by financing activities increased by approximately $59 million, compared to the same period in 2005, primarily due to the following factors, after consideration of the Utility's cash flows from financing activities:

- In 2006, PG&E Corporation paid approximately $228 million in common stock dividends related to the fourth quarter of 2005 and the first quarter of 2006. In comparison, PG&E Corporation's payment of common stock dividends in 2005 related only to the first quarter of 2005; and

- In March 2005, PG&E Corporation repurchased approximately 29.5 million shares of PG&E common stock under an ASR arrangement at an initial price of approximately $1.1 billion (the Utility's repurchase of its common stock from PG&E Corporation totaling $960 million in March 2005 was eliminated in consolidation). There was no similar share repurchase in 2006; however, PG&E Corporation paid certain additional payments of approximately $114 million to GS&Co., as required under the share forward agreement related to the ASR.

CONTRACTUAL COMMITMENTS

PG&E Corporation and the Utility enter into contractual obligations and commitments in connection with business activities. These future obligations primarily relate to financing arrangements (such as long-term debt, preferred stock and certain forms of regulatory financing), purchases of transportation capacity, natural gas and electricity to support customer demand and the purchase of fuel and transportation to support the Utility's generation activities. Refer to Notes 4 and 11 in the Notes to the Condensed Consolidated Financial Statements and the 2005 Annual Report for further discussion.

Utility

The Utility's contractual commitments include power purchase agreements (including agreements with QFs, irrigation districts and water agencies, and renewable energy providers), natural gas supply and transportation agreements, nuclear fuel agreements, operating leases, and other commitments (see the section entitled "Regulatory Matters - Electricity Generation Resources" below for a discussion of new power purchase agreements the Utility has entered into that the Utility has submitted to the CPUC for approval).

CAPITAL EXPENDITURES

The Utility estimates that in 2006 it will invest $2.5 billion in plant and equipment, resulting in a projected weighted average rate base of $15.9 billion for the year ended December 31, 2006. Over the next five years (2006 through 2010), the Utility expects to incur capital expenditures relating to investments to implement an AMI; the acquisition and development of a 530 MW power plant known as Contra Costa Unit 8; and, subject to regulatory approval, infrastructure improvements. In addition, the Utility may incur capital expenditures related to potential investments associated with new generation resources that have not yet been approved by the CPUC, as discussed below under "Regulatory Matters - Electricity Generation Resources ."

Advanced Metering Infrastructure

On July 20, 2006, the CPUC issued a decision approving the Utility's application to install an AMI for virtually all of the Utility's electric and gas customers. The Utility plans to start installing the advanced meters system wide in the fourth quarter of 2006 and to complete installation in 2011.

The CPUC authorized the Utility to recover the $1.74 billion estimated AMI project cost, including an estimated capital cost of $1.4 billion. The $1.74 billion amount includes $1.68 billion for project costs and approximately $54.8 million for costs related to marketing the new critical peak pricing rate option described below. In addition, the Utility is authorized to recover in rates 90% of up to $100 million in costs that exceed $1.68 billion without a reasonableness review. The remaining 10% will not be recoverable in rates. If additional costs exceed the $100 million threshold, the Utility may request recovery of the additional costs, subject to a reasonableness review.

The CPUC also approved the Utility's proposal to offer customers a new voluntary billing option called critical peak pricing, or CPP, under which customers will be able to take advantage of electricity prices that vary by day and hour, potentially reducing their bills by shifting their energy use away from critical peak periods. By shifting energy demand away from critical peak periods, the Utility anticipates that it would need to purchase less power for critical peak periods.

The CPUC's decision allows the Utility to establish separate electric and gas balancing accounts to record the revenue requirements associated with the costs and forecast benefits related to AMI. The Utility will record the revenue

requirement as costs are incurred over the installation period. As new meters are activated, the Utility will record the amount of the forecasted electric and gas operational benefits per meter. The CPUC accepted the Utility's forecast of electric and gas operational benefits to be achieved by AMI. These ratemaking mechanisms will remain in place at least until the Utility's next general rate case, expected to occur for test year 2010 or later. The Utility plans to file an advice letter within 30 days of the CPUC's July 20 decision to implement the Utility's rate proposals to collect the revenue requirement as adopted in the decision. The advice letter will be effective upon CPUC approval.

As previously disclosed, the Utility expects that approximately 89% of AMI costs will be offset by the anticipated operational savings and efficiencies resulting from AMI over the 20-year project life. The Utility expects to achieve additional cost savings resulting from reduced demand as customers choose the CPP billing option.

PG&E Corporation and the Utility cannot guarantee the extent to which the anticipated benefits and cost savings of the AMI project will be realized.

Diablo Canyon Steam Generator Replacement Project

In November 2005, the CPUC approved the Utility's steam generator replacement project, or SGRP, to replace the steam generators at the two nuclear operating units at Diablo Canyon. The Utility plans to replace Unit 2's steam generators in 2008 and replace Unit 1's steam generators in 2009. Because the fabrication of new steam generators requires a long lead-time, in August 2004, the Utility entered into contracts with Westinghouse Electric Company LLC, or Westinghouse, for the design, fabrication and delivery of eight steam generators. Under the contracts, the Utility must pay Westinghouse for all work done and a pro-rated profit up to the time the performance under the contracts is completed or the contracts are terminated. The contracts require progress payments in line with actual expenditures for materials and work completed over the life of the contracts.

As of June 30, 2006, the Utility had incurred approximately $112 million in connection with the SGRP under various construction and installation contracts that the Utility has executed. Based on updated estimates of the cost to complete the SGRP, the Utility estimates that it will spend an additional $517 million to complete the SGRP through 2009.

To implement the SGRP, the Utility requires two permits from San Luis Obispo County: a conditional use permit to store the old generators on-site at Diablo Canyon and a coastal development permit to build temporary structures at Diablo Canyon to house the new generators as they are prepared for installation. At a public hearing on January 12, 2006, the San Luis Obispo County Planning Commission denied approval of both permits. The Utility appealed the denials to the Board of Supervisors of San Luis Obispo County at a public hearing on March 7, 2006, and both permits were approved. On March 20, 2006, the Mothers for Peace, along with the Santa Lucia Chapter of the Sierra Club, appealed the Board of Supervisors' approval of both permits to the California Coastal Commission. The Utility expects that the Coastal Commission will issue a decision on the appeal by the end of 2006. If the Utility's SGRP is delayed, the Utility could incur additional costs to operate and maintain the old steam generators until they can be replaced. If the Utility is ultimately unable to replace the steam generators, the Utility would be required to cease operations at Diablo Canyon and procure power from other sources when the generators were no longer operable in conformance with operating standards.

OFF-BALANCE SHEET ARRANGEMENTS

For financing and other business purposes, PG&E Corporation and the Utility utilize certain arrangements that are not reflected in their Condensed Consolidated Balance Sheets. Such arrangements do not represent a significant part of either PG&E Corporation's or the Utility's activities or a significant ongoing source of financing. These arrangements are used to enable PG&E Corporation or the Utility to obtain financing or execute commercial transactions on favorable terms, and amounts due under these contracts are contingent upon terms contained in these arrangements. For further information related to letter of credit agreements, credit facilities, pollution control bond insurance and bank reimbursement agreements, aspects of PG&E Corporation's accelerated share repurchase program, and PG&E Corporation's guarantee related to certain National Energy and Gas Transmission, Inc., or NEGT, indemnity obligations, see the 2005 Annual Report and Notes 4, 5 and 11 of the Notes to the Condensed Consolidated Financial Statements.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies that are discussed below. Also, refer to Note 11 in the Notes to the Condensed Consolidated Financial Statements for further discussion.

REGULATORY MATTERS

This section of MD&A discusses developments that have occurred in significant regulatory proceedings discussed in the 2005 Annual Report and significant new regulatory proceedings that have been initiated since the 2005 Annual Report was filed with the SEC.

2007 General Rate Case

The Utility's 2007 GRC application included a request for approval of pension contributions of $345 million per year in 2007, 2008 and 2009, and an associated annual revenue requirement of $216 million to fund the portion of each year's pension contribution attributable to the Utility's distribution and generation businesses. In December 2005, the CPUC approved, in part, the Utility's July 2005 petition, giving the Utility permission to file an application for a pension contribution in 2006 and to begin collecting the requested revenue requirement through rates effective January 1, 2006, subject to refund. On March 8, 2006, the Utility requested that the CPUC approve a proposed pension settlement reached among the Utility, the CPUC's DRA and the Coalition of California Utility Employees. The settlement provided for an annual pension-related revenue requirement of $98 million attributable to distribution and generation operations in 2007, 2008 and 2009 (see the "Defined Benefit Pension Plan Contributions" section of "Regulatory Matters" for further information regarding the 2006 pension contribution settlement). On June 15, 2006, the CPUC approved the settlement.

On April 14, 2006, the DRA submitted testimony recommending that the Utility's 2007 revenue requirements be set at a level of approximately $20 million lower than existing 2006 authorized amounts. The DRA's submission of testimony is part of the regular process in every GRC proceeding. The Utility's current requested increase in electric and gas service revenue requirements for 2007 is $359 million and $35 million, respectively, over the authorized 2006 revenue requirements. The Utility's current request is lower than its original December 2, 2005 request because it reflects increases in the Utility's authorized 2006 revenue requirements that became effective on January 1, 2006, including $155 million that the CPUC authorized the Utility to collect to fund a 2006 pension contribution , as discussed in the previous paragraph. In accordance with the settlement agreement discussed in the previous paragraph, the Utility also has lowered its original request for an annual revenue requirement to fund a pension contribution in 2007, 2008 and 2009. Further, the Utility has adjusted its request to reflect testimony filed in the proceeding subsequent to the original application. As a result of the lower amounts requested for 2007 and other revisions, the Utility's current request for attrition increases are approximately $143 million for 2008 and $141 million for 2009, which are net of cost savings that the Utility estimates will result from the implementation of various initiatives to improve the Utility's business processes and systems.

The DRA's recommended net reduction in 2007 revenue requirements from the existing 2006 authorized amounts is comprised of a recommended $17 million increase in electric revenue requirements offset by a recommended $37 million decrease in gas revenue requirements. The DRA's recommended 2007 electric and gas revenue requirement reflects approximately $85 million of differences in the Utility's and the DRA's estimates for depreciation expenses. Among other assumptions as to future costs which differ from the Utility's assumptions, the DRA has assumed that the Utility would make fewer capital expenditures and that some capital additions would be made over a longer period of time than the Utility projected in its application. The DRA assumes that the Utility's average annual capital expenditures for electric and gas distribution, and existing electric generation over the 2007 through 2009 period, would be $1.4 billion, as compared to the Utility's projection of average annual capital expenditures of $1.8 billion over the same period. Capital expenditures related to the GRC do not include projected capital spending related to the AMI project, electric transmission, or proposed new generation resources. In addition, the DRA recommended attrition increases of $98 million for 2008 and $51 million for 2009.

As previously disclosed, due to uncertainty about savings to be realized from the implementation of the various initiatives that the Utility is undertaking to improve its business processes and systems, the Utility proposed a sharing mechanism in its 2007 GRC application by which shareholders and customers would share equally in any earnings over the amount needed to achieve an ROE on GRC rate base equal to the then-authorized ROE plus 50 basis points. The Utility's customers would receive 100% of the earnings over the amount needed to achieve an ROE equal to the then-authorized ROE plus 300 basis points. If the Utility's actual ROE were less than an amount equal to the then-authorized ROE minus 50 basis points, shareholders and customers would share the shortfall equally.

The DRA recommended a sharing mechanism by which the Utility's shareholders would receive 100% of the earnings over the amount needed to achieve an ROE on GRC rate base equal to the then-authorized ROE, up to 50 basis points. Customers would receive 75% of the earnings over the amount needed to achieve the then-authorized ROE plus 50 basis points. Shareholders and customers would share equally in any earnings over the amount needed to achieve an ROE equal to the then-authorized ROE plus 150 basis points. If the Utility's actual ROE were less than an amount equal to the then-authorized ROE, shareholders would bear 100% of the earnings shortfall.

The following table summarizes the Utility's proposed sharing mechanism based on the Utility's 2006 authorized ROE of 11.35%:

ROE	**Customer**	**Shareholder**
Below 10.85%	50%	50%
10.85% - 11.85%	0%	100%
11.86% - 14.35%	50%	50%
Above 14.35%	100%	0%

The following table summarizes the DRA's recommended sharing mechanism for the Utility based on the Utility's 2006 authorized ROE:

ROE	**Customer**	**Shareholder**
Below 11.35%	0%	100%
11.35% - 11.85%	0%	100%
11.86% - 12.85%	75%	25%
Above 12.85%	50%	50%

On April 28, 2006, additional parties, including TURN, submitted testimony in the Utility's 2007 GRC proceeding. TURN's testimony recommends forecasts of certain cost items that differ from those the Utility included in its forecasts. In general, TURN has adopted the DRA's recommendations. The Utility estimates that TURN's recommendations would result in revenue requirements that are approximately $230 million lower than the amount recommended by the DRA, including a recommended annual depreciation expense that would be approximately $194 million less than the annual depreciation expense recommended by the DRA.

The CPUC's 2007 GRC schedule provides for a final decision by December 14, 2006 on all issues except the proposed customer service performance incentive mechanism, for which a decision is expected in April 2007. The Utility has been engaged in confidential settlement discussions with the DRA to resolve all issues in the proceeding. To accommodate continuing settlement discussions, the GRC schedule has been revised. If a proposed settlement agreement is reached, the revised schedule provides that a settlement conference would be held on August 16, 2006, followed by a motion to approve any proposed settlement agreement that would be filed on August 21, 2006. PG&E Corporation and the Utility are unable to predict whether a settlement agreement will be reached and if a settlement agreement is reached, whether it will be approved by the CPUC.

Electricity Generation Resources

California legislation allows the California investor-owned utilities to recover their reasonably incurred wholesale electricity procurement costs. The legislation's mandatory rate adjustment provision requiring the CPUC to adjust retail electricity rates or order refunds, as appropriate, when the forecast aggregate over-collections or under-collections exceed 5% of a utility's prior year electricity procurement revenues (excluding amounts collected for the DWR) expired on January 1, 2006. In December 2004, in approving the California investor-owned utilities' long-term procurement plans, the CPUC decided it would continue the mandatory rate adjustment mechanism for the length of a utility's resource commitment or ten years, whichever is longer.

In the first two quarters of 2006, the Utility filed applications with the CPUC requesting approval of power purchase agreements, as described below. These power purchase agreements were arranged to secure new generation resources in accordance with the Utility's long-term electricity procurement plan, to meet the Utility's resource adequacy requirement, and to meet the Utility's renewable energy requirements. The Utility has requested that the CPUC approve these power purchase agreements, which call for fixed payments totaling approximately $5.3 billion over the terms of the contracts. The Utility has requested that these costs, along with other variable costs, be recovered through the Energy Resource Recovery Account. In addition, as described below, the Utility has executed agreements for new Utility-owned generation resources which have also been submitted to the CPUC for approval.

New Long-Term Generation Resource Commitments

As discussed above, as a result of the Utility's request for offers for long-term generation resources, in April 2006 the Utility filed an application with the CPUC requesting approval of four power purchase agreements, a letter of intent to

enter into a fifth power purchase agreement, and two agreements providing for the construction of generation facilities to be owned and operated by the Utility. The four power purchase agreements that have already been executed would provide approximately 800 MW of capacity with terms from 15 to 20 years. The letter of intent, entered into with an affiliate of Calpine Corporation, provides that a 10-year power purchase agreement relating to 601 MW of capacity would be executed upon satisfaction of certain financial conditions, including that the associated Calpine affiliate emerges from bankruptcy or transfers the project site to a bankruptcy remote entity. If these conditions are not satisfied by October 2006, the letter of intent will terminate. Under the power purchase agreements, the Utility would provide the fuel and in return receive the capacity, energy, and all products generated by the new facilities that would be owned and operated by other parties. Assuming CPUC approval, some of the executed power purchase agreements would be potentially accounted for as capital lease obligations.

One of the two agreements for Utility-owned generation calls for the development and construction of a 657 MW power plant. The other agreement calls for the construction of a 163 MW power plant at the Utility's Humboldt Bay facility.

Assuming the CPUC approves the agreements and that permitting and construction schedules are met, the new generation resources are anticipated to begin delivering power to the grid during the 2009 through 2010 time-frame. The Utility anticipates that the CPUC will issue its decision on the Utility's application by the end of the year.

In addition, as discussed in Note 11 of the Notes to the Condensed Consolidated Financial Statements, pursuant to the Utility's settlement with Mirant Corporation and certain of its subsidiaries, or Mirant, on June 15, 2006, the CPUC approved the Utility's agreement with Mirant to acquire and complete the Contra Costa Unit 8, a 530 MW power plant, subject to certain conditions.

The Utility's 2004 long-term procurement plan indicates that the Utility has a long-term generation resource need for up to 2,200 MW of capacity through 2010, based on certain assumptions. Including Contra Costa Unit 8, the Utility has requested the CPUC to approve long-term resources that together exceed the 2,200 MW forecast included in the Utility's long-term procurement plan due to uncertainties regarding the permitting and construction schedules of the proposed resource additions, whether the conditions to the letter of intent discussed above will be met, the retirement of existing aging power plants, and the rate of future load growth. The Utility has requested the CPUC authorize all of the proposed resource additions to maintain a reliable source of generation supplies in northern California.

Cost Recovery for New Generation Resources

In December 2004, in approving the California investor-owned utilities' long-term procurement plans, the CPUC decided that the utilities should be allowed to recover stranded costs for their long-term resource commitments from departing customers, through a non-bypassable charge, for ten years from the date of signing a power purchase agreement or the date of commercial operation of a utility-owned power plant or the life of the contract, whichever is less. The CPUC also decided that the utilities should be allowed to justify a cost recovery period longer than ten years on a case-by-case basis. In addition, the California legislature has added Assembly Bill 380 to the Public Utilities Code, allowing the CPUC to authorize a non-bypassable charge under certain conditions, without specifying an end date. In approving the Contra Costa Unit 8 acquisition, the CPUC authorized the Utility to collect a non-bypassable charge over 10 years, rather than over thirty years as requested by the Utility (as described above). In its application for approval of the new agreements to meet the Utility's long-term generation resource needs, the Utility requested that the CPUC approve the Utility's recovery of a non-bypassable charge for each commitment over the term of each power purchase agreement or expected life of each Utility-owned generation project, as applicable.

In July 2006, the CPUC issued a decision designating the California investor-owned utilities as responsible for procuring new generation in California. For new generation purchased from third parties under power purchase agreements, the utilities may elect to allocate the net capacity costs (i.e., contract price less energy revenues) to all "benefiting customers" in the utilities' service territory, including direct access customers and community choice aggregation customers. If a utility elects to use this cost allocation method, the net capacity costs are allocated for the term of the contract or 10 years, whichever is less, starting on the date the new generation unit comes on line. If a utility elects to use this cost allocation mechanism, it must use a third-party independent evaluator to oversee the competitive RFO that produces a contract subject to this cost allocation mechanism. Once the contract is selected through the RFO, an independent evaluator must then administer an auction for the energy rights to the contract to minimize the net capacity costs that would be subject to allocation. If no bids are accepted for the energy rights, the utility would dispatch the energy and value the energy at spot market prices for purposes of determining the net capacity costs to be allocated until the next periodic auction. Specific implementation details for the energy rights auction will be addressed in the utilities' long-term procurement plans, to be submitted later this year.

The utilities' owned generation resource costs would not be eligible for recovery under this cost allocation mechanism. As discussed above, these costs would only be eligible for recovery from the utilities' bundled electricity customers and through a non-bypassable charge imposed on departing customers. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the agreements submitted by the Utility for approval and which cost allocation mechanisms would be applicable.

Resource Adequacy

In October 2005, the CPUC issued a decision that sets forth numerous rules in furtherance of the CPUC's resource adequacy policy, including a penalty provision for failure to acquire sufficient capacity needed to meet annual resource adequacy requirements. The penalty is equal to three times the cost of the new capacity the deficient load-serving entity should have secured; however, for 2006 the penalty is set at one-half of the amount. The Utility's CPUC-approved long-term procurement plan forecasts that the Utility will be able to meet future resource adequacy requirements. If the CPUC determines that the Utility has not met the requirements in a particular year, the Utility could be subject to penalties in an amount determined by the CPUC in accordance with the new penalty provision.

In order to meet part of its resource adequacy requirements, in the first quarter of 2006, the Utility requested that the CPUC approve a tolling agreement with Duke Energy Marketing America that represents approximately 1,500 MW of capacity for the next four years . The CPUC approved the request in July 2006; therefore, this tolling agreement would contribute to the fulfillment of the Utility's 2007 to 2010 resource adequacy requirements. In August 2006, the Utility requested CPUC approval of a tolling agreement with Mirant Delta, LLC for capacity of 1,985 MW that would contribute to the fulfillment of the Utility's 2008 to 2011 resource adequacy requirements.

Renewable Energy Contracts

California law established the Renewables Portfolio Standard (RPS) Program, which requires each California retail seller of electricity, except for municipal utilities, to increase its purchases of eligible renewable energy (such as biomass, small hydro, wind, solar and geothermal energy) by at least 1% of its retail sales per year, the annual procurement target, so that the amount of electricity purchased from eligible renewable resources equals at least 20% of its total retail sales by the end of 2017. The CPUC has accelerated the deadline for the 20% goal to 2010 as a matter of policy.

In response to the Utility's 2004 solicitation to enter into contracts with renewable energy providers to meet the Utility's annual procurement target the Utility entered into a 20-year contract for up to 120 MW of annual capacity which was submitted to the CPUC for approval in May 2006. The 2004 solicitation resulted in five signed contracts constituting approximately 2% of annual retail sales. The Utility also has requested that the CPUC approve five contracts from the Utility's 2005 solicitation constituting approximately 2.5% of annual retail sales. A CPUC decision on these six contracts is expected in the third or fourth quarter of 2006. The CPUC also authorized the Utility to begin its 2006 solicitation. The Utility issued its 2006 solicitation on June 30, 2006.

Currently, power from eligible renewable energy resources comprises approximately 12% of the Utility's retail sales. Although the Utility expects it will achieve the 20% target through signed contracts by 2010, actual deliveries of renewable power may not comprise 20% of its bundled retail sales by 2010 due to such factors as the time required to construct the new generation facilities and/or needed transmission capacity. Failure to satisfy the annual procurement targets may result in a penalty of five cents per kWh, with an annual penalty cap of $25 million. Failure to meet the 20% renewable procurement obligation by 2010 may result in additional penalties.

The CPUC has adopted a procedure to enable the utilities to recover the cost of electric transmission and distribution facilities necessary to interconnect renewable energy resources if those costs cannot be recovered in federally-approved rates. In 2006, the Utility will continue to plan for and begin implementation of various transmission projects to improve access to renewable energy resources, among other purposes.

Qualifying Facility Power Purchase Agreements

The CPUC is considering various policy and pricing issues related to power purchased from QFs in several rulemaking proceedings. It is expected that a proposed decision addressing those issues will be issued soon. In April 2006, the Utility and the Independent Energy Producers on behalf of certain QFs entered into a settlement agreement to resolve these issues irrespective of how the CPUC ultimately resolves these issues. The settlement agreement required settling QFs to enter into an amendment of their existing contracts with the Utility to reduce the Utility's energy payments and to establish a new five-year fixed pricing option for non-natural gas-fired QFs. On July 20, 2006, the CPUC approved the settlement

agreement and amendments relating to 121 QFs, representing 52% of the Utility's 2004 QF energy deliveries. The settlement agreement also resolves certain energy crisis claims among the Utility and the settling QFs that are pending in another CPUC proceeding. The settlement agreement and the amendments will become effective after the CPUC decision becomes final and non-appealable on August 21, 2006, assuming no application for rehearing is filed by that date.

FERC Transmission Rate Cases

The Utility's electric transmission revenues and wholesale and retail transmission rates are subject to authorization by the FERC. In August 2005, the Utility filed an application with the FERC requesting an annual retail network transmission revenue requirement of approximately $654 million. On May 19, 2006, the FERC approved a settlement that provides the Utility an annual transmission revenue requirement of $606 million, an increase of approximately $87 million over previously authorized retail transmission rates, effective March 1, 2006.

On August 1, 2006, the Utility filed an application with the FERC requesting an annual transmission revenue requirement of approximately $719 million, effective October 1, 2006. The proposed rates represent an increase of approximately $113 million over current authorized rates. PG&E Corporation and the Utility are unable to predict what amount of revenue requirements and the effective date the FERC will authorize, when a final decision will be received from the FERC, or the impact it will have on their results of operations.

Scheduling Coordinator Costs

Before the Independent System Operator, or ISO, commenced operation in 1998, the Utility had entered into several wholesale electric transmission contracts with various governmental entities. After the ISO began operations, the Utility served as the SC with the ISO for these existing wholesale transmission customers, or ETCs. The ISO billed the Utility for providing certain services associated with this scheduling. These ISO charges are referred to as "SC costs." The SC costs were initially tracked in the transmission revenue balancing account, or TRBA, in order to recover the SC costs from retail and new wholesale transmission customers, or TO Tariff customers.

In 1999, a FERC administrative law judge, or ALJ, ruled that the Utility could not recover the SC costs through the TRBA and instead should seek to recover the SC Costs from the ETCs. The Utility appealed this ruling. In January 2000, the FERC accepted a filing by the Utility to establish the Scheduling Coordinator Services, or SCS, Tariff, to serve as an alternative mechanism for recovery of the SC costs from the ETCs in case the Utility's appeal was unsuccessful and the Utility was ultimately unable to recover these costs in the TRBA . In August 2002, the FERC affirmed the ALJ's 1999 ruling that the Utility should refund to TO Tariff customers the SC costs that the Utility had collected through the TRBA. In the absence of an order from the FERC granting recovery of these costs through the TRBA, the Utility removed the SC costs from the TRBA and reflected the SC costs as accounts receivable under the SCS Tariff. The Utility appealed the FERC's decision to the U.S. Court of Appeals for the District of Columbia Circuit, or D.C. Circuit. In June 2004, the Utility began billing the ETCs under the SCS Tariff for SC charges retroactive to April 1, 1998. In the course of the SCS Tariff proceeding at the FERC, the Utility entered into settlement agreements with several ETCs under which the settling ETCs paid the Utility compromised amounts in full satisfaction of past due SC costs. Most of the settlement agreements provided that if the Utility's pending appeal to the D.C. Circuit was successful the Utility would refund the settlement amounts paid by the ETCs.

In July 2005, the D.C. Circuit issued an order finding that the Utility was not barred from recovering the SC costs through the TRBA and remanding the matter to the FERC for further action. In December 2005, the FERC issued an order concluding that the Utility should recover the SC costs through the TRBA mechanism or through bilateral agreements with the ETCs, but could not recover the costs through the SCS Tariff, and terminating the SCS Tariff proceeding. On May 22, 2006, the FERC issued an order further clarifying that the Utility could recover through the TRBA all of the costs that it had incurred as an SC and ordered the Utility to refund to the ETCs all amounts paid by the ETCs to the Utility pursuant to the SCS Tariff. As of July 31, 2006, the Utility had made refunds to the ETCs pursuant to the FERC's May 2006 order and the settlement agreements that required refunds to be made if the Utility's appeal was successful.

On April 4, 2006, the Utility filed an application with the FERC seeking approval of the $109 million that the Utility recorded as SC costs from April 1998 through September 30, 2005, together with interest of $47 million accrued over that time period. The Utility requested that the FERC permit the Utility to recover these costs from TO Tariff customers over three and one half years. On June 22, 2006, the Utility filed additional information to supplement the application as directed by the FERC. Unless the FERC requests additional information, the Utility expects a FERC order on the application before September 1, 2006. The Utility also filed an advice letter with the CPUC notifying the CPUC that the Utility will seek to pass through the portion of any FERC-approved SC costs that is allocable to the Utility's retail electric customers . In light of these events, in the quarter ended June 30, 2006, the Utility's net income increased by approximately $22 million, or $36 million pre-tax, reflecting the portion of SC costs determined to be probable of recovery through the TRBA and the reversal of a

reserve for SC costs under the SCS Tariff which was terminated by the FERC, offset by the SCS refunds to the ETCs.

The Utility cannot predict when a final decision will be received from the FERC or the CPUC or what impact it will have. While PG&E Corporation and the Utility believe that 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, the Utility's net income could increase by approximately $40 million if the FERC ultimately approves for recovery all of the costs included in the April 4, 2006 filing and the CPUC approves the portion of any FERC-approved SC costs that is allocable to the Utility's retail electric customers.

Spent Nuclear Fuel Storage Proceedings

Under the Nuclear Waste Policy Act of 1982, the U.S. Department of Energy, or DOE, is responsible for the transportation, permanent storage and disposal of spent nuclear fuel and high-level radioactive waste. The Utility has signed a contract with the DOE to provide for the disposal of spent nuclear fuel and high-level radioactive waste from the Utility's two nuclear power facilities at Diablo Canyon. Under the Utility's contract with the DOE, if the DOE completes a storage facility by 2010, the earliest that Diablo Canyon's spent fuel would be accepted for storage or disposal is expected to be 2018. At the projected level of operation for Diablo Canyon, the Utility's current facilities are able to store on-site all spent fuel produced through approximately 2010 for Unit 1 and 2011 for Unit 2.

In March 2004, the Nuclear Regulatory Commission, or NRC, authorized the Utility to build an on-site dry cask storage facility to store spent fuel. The license is effective for 20 years, with an option to renew for another 20 years under the applicable regulations. Several interveners in that proceeding filed an appeal of the NRC's decision with the U.S. Court of Appeals for the Ninth Circuit, or the Ninth Circuit, on the grounds that the NRC should have considered the terrorist threat against the dry cask storage facility as part of the environmental review under the National Environmental Policy Act or NEPA . On June 2, 2006, the Ninth Circuit granted the appeal in part and ordered that the case be remanded to the NRC for further consideration of the terrorist threat issue as part of a supplemental NEPA assessment.   Before issuing the license in March 2004, the NRC reviewed the terrorist threat issue as part of its safety and design assessment under the Atomic Energy Act and that review was found to be sufficient by the Ninth Circuit. Currently, the Utility is considering whether to request the Ninth Circuit to reconsider its decision or to seek further review of the Ninth Circuit's decision by the U.S. Supreme Court.

In addition, some of the interveners in the case have filed a request with the NRC seeking an injunction to prevent the Utility from loading used fuel in its on-site storage facility until the NRC has completed its additional environmental review. The interveners also seek a declaratory order from the NRC that if the Utility proceeds with construction of the on-site storage facility prior to completion of the NRC's additional environmental review, it does so at the risk that a new permit may be denied or that it may have to change the design and construction of the facility in response to the environmental review. The Utility believes that prior legal precedent allows it to continue construction of the on-site storage facility and to load fuel and commence operations of the facility while the supplemental environmental assessment is still pending at the NRC. On July 17, 2006 the Utility filed a response at the NRC objecting to the intervener's request for injunctive and declaratory relief.

Construction of the on-site dry cask storage facility began in the third quarter of 2005 and is expected to be completed by 2008. In November 2005, the NRC authorized the Utility to install a temporary storage rack in each unit's existing spent fuel storage pool that would permit the Utility to operate Unit 1 until 2010 and Unit 2 until 2011. The Utility anticipates that it would complete the installation of the temporary storage racks by December 2006. If the Utility is unable to complete the dry cask storage facility, or if construction is delayed beyond 2010, and if the Utility is otherwise unable to increase its on-site storage capacity, it is possible that the operation of Diablo Canyon may have to be curtailed or halted as early as 2010 with respect to Unit 1 and 2011 with respect to Unit 2 and until such time as additional spent fuel can be safely stored. If electricity from Diablo Canyon were unavailable, the Utility would be required to purchase electricity from other more expensive sources to meet its customers' demand.

Defined Benefit Pension Plan Contribution

On June 16, 2006, the CPUC issued a decision adopting a pension settlement among the Utility, the DRA, and the Coalition of California Utility Employees that will allow the Utility to recover revenue requirements associated with annual contributions to fund the Utility's pension plan from 2006 to 2009. The Utility will fund a net pension contribution of $250 million in 2006 and $153 million annually for the years 2007, 2008 and 2009. On a projected basis, these contributions will bring pension trust plan to fully funded status as of January 1, 2010 . The decision resolved the Utility's application for 2006 pension contribution funding as well as the Utility's separate request for pension contribution funding for 2007, 2008 and 2009 made in the 2007 GRC application.

For 2006, the decision authorized $155 million revenue requirement attributable to its distribution and generation operations, or GRC line of business, to fund a net pension contribution of $250 million. Approximately $20 million of the $250 million contribution relates to revenue requirements for gas transmission and storage, electric transmission, and nuclear decommissioning, which have been or will be addressed in other CPUC or FERC proceedings. The remaining 2006 contribution amount will be capitalized. As a result of the CPUC’s final decision approving the pension contribution settlement on June 16, 2006, the Utility made the 2006 authorized net pension contribution of $250 million on July 20, 2006.

The $155 million revenue requirement for 2006 that the Utility is currently collecting in rates for its GRC line of business pursuant to an earlier decision is no longer subject to refund. For 2007, 2008 and 2009, the annual pension-related revenue requirement attributable to the GRC line of business will decrease to approximately $98 million.

CPUC Proceeding Regarding Holding Companies and their Affiliates

On June 29, 2006, the CPUC issued an amendment to an October 2005 Order Instituting Rulemaking, or OIR, to allow the CPUC to re-examine the relationship between California energy utilities and their parent holding companies and affiliates in furtherance of the CPUC’s goals to ensure that California’s regulated utilities meet their public service obligations and that the utilities do not favor or otherwise engage in preferential treatment of their affiliates . In the amended OIR, the CPUC stated that it has amended the scope and schedule of the original OIR and requested public comment on the extent to which there should be future revisions to (1) the CPUC’s rules governing transactions and relationships among the parent holding companies, their utility subsidiaries, and other affiliates of the parent holding companies, and (2) the CPUC’s requirements to report compensation paid to executive officers and employees of regulated utilities, their holding companies, and their affiliates in the western United States energy market . In the amended OIR, the CPUC noted that the original intent of its affiliate transaction rules had not been fulfilled largely due to the numerous exceptions to the rules and to what the CPUC considered to be the utilities’ overly-narrow interpretations of the rules. The CPUC’s schedule calls for opening and reply comments to be filed August 7 and 18, 2006, respectively , draft rule revisions to be issued the week of September 5, 2006, a draft CPUC decision to be issued October 10, 2006, and a final decision to be voted on at the CPUC’s meeting to be held on November 9, 2006.

PG&E Corporation expects to vigorously oppose the adoption by the CPUC of any new rules that would restrict the functioning of the holding company structure. PG&E Corporation and the Utility cannot predict whether any rules that the CPUC may adopt will have a material impact on their results of operations or financial condition.

Pending CPUC Investigation

In February 2005, the CPUC issued a ruling opening an investigation into the Utility’s billing and collection practices and credit policies. The investigation was begun at the request of The Utilities Reform Network, or TURN, after the CPUC's January 13, 2005 decision that characterized the definition of “ billing error ” in a revised Utility tariff to include delayed bills and Utility-caused estimated bills as being consistent with “ existing CPUC policy, tariffs, and requirements. ” The Utility contends that prior to the CPUC’s January 13, 2005 decision, “ billing error ” under the Utility's former tariffs did not encompass delayed bills or Utility-caused estimated bills. The Utility’s petition asking the appellate court to review the CPUC's decision denying rehearing of its January 13, 2005 decision is still pending.

On February 3, 2006, the CPUC’s Consumer Protection and Safety Division, or CPSD, and TURN submitted their reports to the CPUC concluding that the Utility violated applicable tariffs related to delayed and estimated bills. The CPSD recommended that the Utility refund to customers $117 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. TURN recommended that the Utility refund to customers $53 million, plus interest at the three-month commercial paper interest rate, that allegedly was collected in violation of the tariffs. The two refunds are not additive. The CPSD also recommended that the Utility pay fines of $6.75 million, while TURN recommends fines in the form of a $1 million contribution to Relief for Energy Assistance through Community Help. Both the CPSD and TURN recommend that refunds and fines be funded by shareholders. In May and July 2006, the CPSD and TURN indicated they had reduced their recommended refund amounts to approximately $54 million and $36 million, respectively, plus interest at the three-month commercial paper interest rate. A decision is expected from the CPUC by the end of 2006.

If the CPUC finds that the Utility violated applicable tariffs or the CPUC’s orders or rules, the CPUC may seek to order the Utility to refund any amounts collected in violation of tariffs, plus interest, to customers who paid such amounts. In addition, if the CPUC finds that the Utility violated applicable tariffs or the CPUC’s orders or rules, the CPUC may seek to impose penalties on the Utility.

PG&E Corporation and the Utility do not expect the outcome of this matter will have a material adverse effect on PG&E Corporation's or the Utility's financial condition or results of operations .

Energy Efficiency Rulemaking

On April 13, 2006, the CPUC issued an OIR to consider establishing new energy efficiency policies and programs, including mechanisms that would provide incentives or impose penalties on the investor-owned utilities depending on the extent to which the utilities successfully implement their 2006-2008 energy efficiency programs. Initial proposals addressing the incentive mechanism were filed by various parties on June 16, 2006. Under the Utility's initial proposed incentive mechanism, 85% of the net present value of energy efficiency programs (net benefits) would accrue to ratepayers, and 15% would accrue to shareholders. The Utility has proposed that it would begin earning incentives when it reached 70% of the CPUC-approved energy savings targets. Other parties have proposed that the Utility begin earning incentives only when the Utility reached 100 percent of the CPUC-approved energy savings targets and accrue earnings of only 1-3% of the net benefits. All parties have proposed penalties for poor performance in achieving the CPUC's adopted savings targets. The Utility has proposed that if it achieves less than 40% of the savings targets, and ratepayer benefits fall short of the Utility's expenditures, the Utility would provide ratepayers that shortfall. Other parties have proposed penalties which would be imposed if the Utility achieves less than 90% of the CPUC's savings targets. It is anticipated that the CPUC will issue a final decision on the adoption of a shareholder incentive/penalty mechanism in late 2006 or in early 2007. Actual shareholder incentives or penalties may not be realized for several years, depending upon the final adopted mechanism. In addition to proposed mechanisms for shareholder incentives or penalties, other issues to be considered include evaluation, measurement and verification the Utility's energy efficiency implementation results; energy and water savings; and planning for energy efficiency programs to be implemented in 2009-2011. PG&E Corporation and the Utility are unable to predict what rules and policies the CPUC may ultimately adopt and what impact the adopted shareholder incentive/penalty mechanism may have on their financial condition and results of operations.

Cost of Capital

On July 14, 2006, a proposed decision was issued for consideration by the CPUC that recommends the approval of the Utility's request that the requirement for the Utility to file a 2007 cost of capital application be waived. Instead the proposed decision recommends that the Utility be required to file a cost of capital application in 2007 for the 2008 test year. The Utility's currently authorized cost of capital on its assets that are subject to CPUC regulation will remain in effect until changed by a future CPUC decision. The proposed decision also recommended that the CPUC open an investigation to address the cost of capital models used by the CPUC to estimate the cost of capital.

PG&E Corporation and the Utility cannot predict whether the proposed decision will be adopted by the CPUC.

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 transmission and storage, other goods and services, and other aspects of their business. PG&E Corporation and the Utility categorize market risks as price risk and interest rate risk. For a comprehensive discussion of PG&E Corporation's market risks, see "Risk Management Activities" in the MD&A section of the 2005 Annual Report. The following disclosures omit certain information that has not changed since the 2005 Annual Report was filed with the SEC.

Price Risk

Natural Gas Transmission and Storage

The Utility uses value-at-risk to measure the Utility's exposure to price and volumetric risks that could impact revenues due to changes in market prices, customer demand and weather. Value-at-risk measures this exposure over a rolling 12-month forward period and assumes that the contract positions are held through expiration. This calculation is based on a 99% confidence level, which means that there is a 1% probability that the impact to revenues on a pre-tax basis, over the rolling 12-month forward period, will be at least as large as the reported value-at-risk. Value-at-risk uses market data to quantify the Utility's price exposure. When market data is not available the Utility uses historical data or market proxies to extrapolate the required market data. Value-at-risk as a measure of portfolio risk has several limitations, including but not

limited to, inadequate indication of the exposure to extreme price movements and the use of historical data or market proxies may not adequately capture portfolio risk.

The Utility's value-at-risk calculated under the methodology described above was approximately $41 million and $31 million at June 30, 2006 and December 31, 2005, respectively. The Utility's high, low and average value-at-risk during the six months ended June 30, 2006 was approximately $41 million, $22 million and $31 million, respectively. The Utility's high, low and average value-at-risk during the year ended December 31, 2005 was approximately $43 million, $31 million and $36 million, respectively.

Convertible Subordinated Notes

As of June 30, 2006, PG&E Corporation has outstanding $280 million of 9.50% Convertible Subordinated Notes, or Convertible Subordinated Notes, that are scheduled to mature on June 30, 2010. Holders of the Convertible Subordinated Notes are entitled to receive "pass-through dividends" at the same payout ratio as common shareholders with the number of shares determined by dividing the principal amount of the Convertible Subordinated Notes by the conversion price.

In accordance with SFAS No. 133, " Accounting for Derivative Instruments and Hedging Activities, " the dividend participation rights component is considered to be an embedded derivative instrument and, therefore, must be bifurcated from the Convertible Subordinated Notes and recorded at fair value in PG&E Corporation's Condensed Consolidated Financial Statements. Changes in the fair value are recognized in PG&E Corporation's Condensed Consolidated Statements of Income as a non-operating expense or income (included in Other expense, net). At June 30, 2006 and December 31, 2005, the total estimated fair value of the dividend participation rights component, on a pre-tax basis, was approximately $86 million and $92 million, respectively, of which $23 million and $22 million, respectively, is classified as a current liability (in Current Liabilities - Other) and $63 million and $70 million, respectively, is classified as a noncurrent liability (in Noncurrent Liabilities - Other).

Accelerated Share Repurchase

As discussed above under " Liquidity and Financial Resources, " on March 28, 2006, PG&E Corporation entered into a new share forward agreement with GS&Co. to complete the ASR. Under the new share forward agreement, PG&E Corporation and GS&Co. were required to make certain payments, including a price adjustment with respect to the remaining 11,385,000 shares subject to the agreement based on the difference between the specified forward price of $34.75 per share and the average of the daily VWAP from March 29, 2006 through June 8, 2006. On June 13, 2006, PG&E Corporation paid GS&Co. approximately $56 million as a price adjustment to settle the arrangement. PG&E Corporation has no remaining obligations under the ASR.

Interest Rate Risk

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 June 30, 2006, if interest rates changed by 1% for all current variable rate debt issued 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.

CRITICAL ACCOUNTING POLICIES

The preparation of Condensed Consolidated Financial Statements in accordance with accounting principles generally accepted in the United States of America 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 to their complexity, because their application is 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 discussed in detail in the 2005 Annual Report. They include:

- Regulatory Assets and Liabilities;
- Unbilled Revenues;
- Environmental Remediation Liabilities;

- Asset Retirement Obligations;
- Income Taxes; and
- Pension and Other Postretirement Benefits.

For the period ended June 30, 2006, there were no changes in the methodology for computing critical accounting estimates, no additional accounting estimates met the standards for critical accounting policies, and there were no material changes to the important assumptions underlying the critical accounting estimates.

NEW ACCOUNTING POLICIES

In December 2004, the Financial Accounting Standards Board, or FASB, issued SFAS No. 123 (revised December 2004), “Share-Based Payment,” or SFAS No. 123R. SFAS No. 123R requires that the cost of all share-based payment transactions be recognized in the financial statements and establishes a fair-value measurement objective in determining the value of such costs.

Effective January 1, 2006, PG&E Corporation and the Utility adopted the fair value recognition provisions of SFAS No. 123R. The impact of adopting SFAS No. 123R is disclosed in Note 2 and Note 8 to the Condensed Consolidated Financial Statements. See Note 2 for additional new accounting policies.

ACCOUNTING PRONOUNCEMENTS ISSUED BUT NOT YET ADOPTED

Refer to Note 2 in the Notes to the Condensed Consolidated Financial Statements for further discussion.

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 their financial condition or results of operations.

ENVIRONMENTAL AND LEGAL MATTERS

PG&E Corporation and the Utility are subject to laws and regulations established both to maintain and improve the quality of the environment. Where PG&E Corporation's and the Utility's properties contain hazardous substances, these laws and regulations may require PG&E Corporation and the Utility to remove those substances or to remedy effects on the environment. As described in Note 11 of the Notes to the Condensed Consolidated Financial Statements, the Utility had an undiscounted environmental remediation liability of approximately $514 million at June 30, 2006, and approximately $469 million at December 31, 2005. The increase in the undiscounted environmental remediation liability is partly due to a $30 million increase in estimated costs as a result of changes in the California Regional Water Quality Control Board’s imposed remediation levels associated with the Utility’s gas compressor station located near Hinkley, California. Costs incurred at this facility are not recoverable from customers and, as a result net income was reduced by $18 million for the three and six months ended June 30, 2006. In addition, the Utility increased its estimated remediation costs associated with its gas compressor station located near Topock, Arizona by $24 million. In accordance with the hazardous waste ratemaking mechanism discussed in Note 11 of the Notes to the Condensed Consolidated Financial Statements, 90% of this additional cost will be recoverable in rates.

In the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. As described in Note 11 of the Notes to the Condensed Consolidated Financial Statements, the accrued liability for legal matters is included in PG&E Corporation’s and the Utility’s other current liabilities in the Condensed Consolidated Balance Sheets, and totaled approximately $60 million at June 30, 2006, and $388 million at December 31, 2005. The Utility has accrued approximately $19 million with respect to the Chromium Litigation, as described in Note 11of the Notes to the Condensed Consolidated Financial Statements. PG&E Corporation and the Utility do not believe that the ultimate outcome of the Chromium Litigation will have an additional material adverse impact on their financial condition or results of operations .

As disclosed in PG&E Corporation’s and the Utility’s 2005 Annual Report, the U.S. Environmental Protection Agency, or EPA, published regulations under Section 316(b) of the Clean Water Act for cooling water intake structures. The

regulations affect existing electricity generation facilities using over 50 million gallons per day, typically including some form of "once-through" cooling such as that used at Diablo Canyon. These regulations establish a set of performance standards that vary with the type of water body and that are intended to reduce impacts to aquatic organisms. In June 2006, the California State Water Resources Control Board issued a proposed policy to implement these new EPA regulations in California. Unlike the EPA regulations which allow site-specific compliance determinations if a facility's cost of compliance is significantly greater than either the benefits achieved or the compliance costs considered by the EPA, the proposed California policy would not permit site-specific cost/benefit determinations. If adopted, the Utility may be required to incur material capital expenditures to achieve compliance with these regulations or cease operations temporarily or permanently. If the Utility is unable to recover the costs of compliance with these regulations, or if the Utility ceased to operate Diablo Canyon, PG&E Corporation’s and the Utility’s future financial results and condition would be materially and adversely affected.

ITEM 3: QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PG&E Corporation's and the Utility's primary market risk results from changes in energy prices. 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 the Utility's disclosure controls and procedures as of June 30, 2006, 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, or the Act, is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the Act is accumulated and communicated to PG&E Corporation’s and the Utility’s management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of January 1, 2004, PG&E Corporation and the Utility adopted Financial Accounting Standards Board, or FASB, revision to FASB Interpretation No. 46, “Consolidation of Variable Interest Entities,” or FIN 46R. In accordance with FIN 46R, the Utility consolidated the assets, liabilities and non-controlling interests of a low-income housing partnership that was determined to be a variable interest entity, or VIE, under FIN 46R. PG&E Corporation and the Utility do not have the legal right or authority to assess the internal controls of the VIE. Therefore, PG&E Corporation's and the Utility's evaluation of disclosure controls and procedures performed as of June 30, 2006, did not include this entity in that evaluation. PG&E Corporation and the Utility have not designed, established, or maintained disclosure controls and procedures for the consolidated VIE.

There were no changes in internal controls over financial reporting that occurred during the quarter ended June 30, 2006, that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal controls over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Pacific Gas and Electric Company Chapter 11 Filing

The Utility's Chapter 11 plan of reorganization became effective on April 12, 2004. The plan of reorganization incorporated the terms of the Settlement Agreement. Although the Utility's operations are no longer subject to the oversight of the bankruptcy court, the bankruptcy court retains jurisdiction to hear and determine disputes arising in connection with the interpretation, implementation or enforcement of (1) the Settlement Agreement, (2) the plan of reorganization, and (3) the bankruptcy court's December 22, 2003 order confirming the plan of reorganization, or confirmation order. In addition, the bankruptcy court retains jurisdiction to resolve remaining disputed claims.

On March 16, 2006, the Ninth Circuit dismissed as moot an appeal of the confirmation order that had been filed by two former commissioners of the CPUC who did not vote to approve the Settlement Agreement. On March 30, 2006, one of the two former commissioners filed a petition for rehearing with the Ninth Circuit. On April 7, 2006, the Ninth Circuit denied the petition. The time period during which the former commissioners could have filed a petition for rehearing with the U.S. Supreme Court has expired, rendering the confirmation order final and no longer subject to appeal.

For more information regarding the Utility's Chapter 11 proceeding, see "Part I, Item 3: Legal Proceedings" of the 2005 Annual Report and Note 10 of the Notes to the Condensed Consolidated Financial Statements included in this report.

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

For information regarding this matter, see "Part I, Item 3: Legal Proceedings" in the 2005 Annual Report.

Diablo Canyon Power Plant

For information regarding matters relating to the Diablo Canyon Power Plant, see "Part I, Item 3: Legal Proceedings" in the 2005 Annual Report.

Compressor Station Chromium Litigation

In accordance with the terms of a settlement agreement entered into on February 3, 2006, on April 21, 2006, the Utility released $295 million from escrow for payment to approximately 1,100 plaintiffs who had filed complaints against the Utility in the Superior Court for the County of Los Angeles, or Superior Court. The Superior Court has dismissed the ten complaints covered by the settlement agreement. There are three complaints filed by approximately 125 plaintiffs who did not participate in the settlement that are still pending in the Superior Court. The plaintiffs allege that exposure to chromium at or near the Utility's compressor station at Hinkley, California, caused personal injuries, wrongful deaths, or other injuries.

For more information regarding the Chromium Litigation, see "Part I, Item 3: Legal Proceedings " in the 2005 Annual Report and Note 11 to the Notes to the Condensed Consolidated Financial Statements included in this report.

With respect to the unresolved claims, the Utility will continue to pursue appropriate defenses, including the statute of limitations, the exclusivity of workers' compensation laws, lack of exposure to chromium, and the inability of chromium to cause certain of the illnesses alleged. PG&E Corporation and the Utility do not expect that the outcome with respect to the remaining unresolved claims will have a material adverse effect on their financial condition or results of operations.

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

On April 5, 2006, the Ninth Circuit denied PG&E Corporation's request for an *en banc* rehearing regarding the Ninth Circuit's remand of plaintiffs' restitution claims back to the San Francisco Superior Court. PG&E Corporation filed a petition seeking review of the Ninth Circuit's ruling with the U.S. Supreme Court on June 30, 2006.

PG&E Corporation believes that the California Attorney General's and City and County of San Francisco's allegations have no merit and will continue to vigorously respond to and defend against the litigation. PG&E Corporation believes that the ultimate outcome of this matter would not result in a material adverse effect on PG&E Corporation's financial condition or results of operations.

For more information regarding these cases, see “Part I, Item 3: Legal Proceedings ” of the 2005 Annual Report.

ITEM 1A. RISK FACTORS

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility is set forth under the heading “ Management's Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors” in the 2005 Annual Report. The last risk factor appearing in the 2005 Annual Report discussed the possibility that the bankruptcy court’s order confirming the Utility’s Chapter 11 plan of reorganization could be overturned or modified on appeal. As disclosed above, under “Item 1. Legal Proceedings - Pacific Gas and Electric Company Chapter 11 Filing,” the time period during which the appellants could have filed a petition for rehearing with the U.S. Supreme Court has expired, rendering the confirmation order final and no longer subject to appeal. There have been no other material changes in the risks related to an investment in PG&E Corporation’s or the Utility’s securities that have been disclosed in the 2005 Annual Report. In addition, the section of this report entitled “Forward Looking Statements” appearing in Part I, Item 2. M anagement's Discussion and Analysis of Financial Condition and Results of Operations, lists some of the factors that could affect PG&E Corporation’s and the Utility’s future results of operations and financial condition. Although PG&E Corporation and the Utility are not able to predict all the factors that may affect future results, t he listed factors and the risks discussed in the Annual Report could cause actual results to differ materially from the results expected or anticipated by management as expressed or implied by the forward-looking statements made in the 2005 Annual Report and in this report.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

Neither PG&E Corporation nor t he Utility made any sales of unregistered equity securities during the quarter ended June 30, 2006, the period covered by this report.

Issuer Purchases of Equity Securities

PG&E Corporation common stock:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs
April 1 through April 30, 2006	-	$ -	-	$ 500,000,000
May 1 through May 31, 2006	-	$ -	-	$ 500,000,000
June 1 through June 30, 2006	-	$ -	-	$ 500,000,000
Total	-	$ -	-	$ 500,000,000

(1) On October 19, 2005, the PG&E Corporation Board of Directors authorized the repurchase of up to $1.6 billion in shares of PG&E Corporation's common stock from time to time, but no later than December 31, 2006. The program was publicly announced in a Current Report on Form 8-K filed by PG&E Corporation on October 21, 2005. As described in a Current Report on Form 8-K filed by PG&E Corporation on November 18, 2005, PG&E Corporation entered into an accelerated share repurchase arrangement with Goldman Sachs & Co., Inc., or GS&Co., on November 16, 2005, or the November 16 ASR, under which PG&E Corporation repurchased 31,650,300 shares of its outstanding common stock at an initial price of $34.75 per share and an aggregate price of approximately $1.1 billion. The forward share component of the November 16 ASR was terminated in accordance with its terms on March 28, 2006. In connection with the termination, PG&E Corporation paid GS&Co. approximately $58 million (net of amounts payable by GS&Co. to PG&E Corporation), including a price adjustment based on the difference between $34.75 per share, and the volume weighted average price, or VWAP, of PG&E Corporation common stock from November 17, 2005 through March 28, 2006. On March 28, 2006, PG&E Corporation entered into a new share forward agreement with GS&Co. to complete the share forward component of the November 16 ASR. The new forward share agreement was terminated in accordance with its terms on June 8, 2006. In connection with the termination, on June 13, 2006, PG&E Corporation paid GS&Co. approximately $56 million (net of amounts payable by GS&Co. to PG&E Corporation), including a price adjustment based on the difference between $34.75 per share, and the VWAP of PG&E Corporation common stock from March 29, 2006 through June 8, 2006.

During the second quarter of 2006, Pacific Gas and Electric Company did not redeem or repurchase any shares of its various series of preferred stock outstanding.

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

On April 19, 2006, PG&E Corporation and Pacific Gas and Electric Company held their joint annual meeting of shareholders. Information regarding the voting results of the meetings is contained in the PG&E Corporation and the Utility's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, Part II, Item 4, and such information is incorporated by reference into this report.

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 and six months ended June 30, 2006 was 3.18 and 3.16, respectively. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three and six months ended June 30, 2006, was 3.09 and 3.08 respectively. 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 333-109994 relating to various series of the Utility's first preferred stock and its senior notes, respectively.

ITEM 6. EXHIBITS

3.1	Bylaws of PG&E Corporation, as amended on June 21, 2006

3.2	Bylaws of Pacific Gas and Electric Company, as amended on June 21, 2006
10	Supplemental Confirmation dated March 28, 2006, supplementing Master Confirmation Agreement dated November 16, 2005 between PG&E Corporation and Goldman Sachs & Co., Inc., incorporated by reference from PG&E Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, Ex. 10
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
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.

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

G. Robert Powell

G. Robert Powell
Vice President and Controller
(duly authorized officer and principal accounting officer)

PACIFIC GAS AND ELECTRIC COMPANY

G. Robert Powell

G. Robert Powell
Vice President and Controller
(duly authorized officer and principal accounting officer)

Dated: August 2, 2006

EXHIBIT INDEX

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Exhibit 3.1

Bylaws
of
PG&E Corporation
amended as of June 21, 2006

Article I.
SHAREHOLDERS.

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

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

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

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

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation. To be timely, the shareholder’s written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year’s annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder’s written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder’s written notice to be timely must be so received not later than the close of business on the tenth day following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder's written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder's written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation's books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, if the shareholder's written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section.

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

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

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

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

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

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

Consents to corporate action shall be valid for a maximum of sixty days after the date of the earliest dated consent delivered to the Corporation. Consents may be revoked by written notice (i) to the Corporation, (ii) to the shareholder or shareholders soliciting consents or soliciting revocations in opposition to action by consent proposed by the Corporation (the “Soliciting Shareholders”), or (iii) to a proxy solicitor or other agent designated by the Corporation or the Soliciting Shareholders.

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

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

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

Unless the consent of all shareholders entitled to vote have been solicited in writing, the Corporation shall give prompt notice to the shareholders in accordance with

California Corporations Code Section 603 of the results of any consent solicitation or the taking of the corporate action without a meeting and by less than unanimous written consent.

Article II.
DIRECTORS.

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

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

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

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

5. **Special Meetings** . The Chairman of the Board, the Vice Chairman of the Board, the Chairman of the Executive Committee, the President, or any five directors may call a special meeting of the Board of Directors at any time. Notice of the time and place of special meetings shall be given to each Director by the Corporate Secretary. Such notice shall be delivered personally or by telephone (or other system or technology designed to record and communicate messages, including facsimile,

electronic mail, or other such means) to each Director at least four hours in advance of such meeting, or sent by first-class mail or telegram, postage prepaid, at least two days in advance of such meeting.

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

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

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

Article III.
OFFICERS.

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

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

3. **Vice Chairman of the Board** . The Vice Chairman of the Board, if that office be filled, shall have such duties and responsibilities as may be prescribed by the

Board of Directors, the Chairman of the Board, or the Bylaws. The Vice Chairman of the Board shall be the chief executive officer of the Corporation if so designated by the Board of Directors. In the absence of the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Board of Directors and of the shareholders; and, in the absence of the Chairman of the Executive Committee and the Chairman of the Board, the Vice Chairman of the Board shall preside at all meetings of the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

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

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

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

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

7. **General Counsel** . The General Counsel shall be responsible for handling on behalf of the Corporation all proceedings and matters of a legal nature. The General Counsel shall render advice and legal counsel to the Board of Directors, officers, and employees of the Corporation, as necessary to the proper conduct of the business. The General Counsel shall keep the management of the Corporation informed of all significant developments of a legal nature affecting the interests of the Corporation.

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

8. **Vice Presidents** . Each Vice President, if those offices are filled, shall have such duties and responsibilities as may be prescribed by the Board of Directors,

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

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

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

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

10. **Treasurer** . The Treasurer shall have custody of all moneys and funds of the Corporation, and shall cause to be kept full and accurate records of receipts and disbursements of the Corporation. The Treasurer shall deposit all moneys and other valuables of the Corporation in the name and to the credit of the Corporation in such depositaries 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. **Certificates; Direct Registration System** . Shares of the Corporation's capital stock may be certificated or uncertificated, as provided under California law. Any certificates that are issued shall be signed in the name of the Corporation by the Chairman of the Board, the Vice Chairman of the Board, the President, or a Vice President and by the Chief Financial Officer, an Assistant Treasurer, the Corporate Secretary, or an Assistant Secretary, certifying the number of shares and the class or series of shares owned by the shareholder. Any or all of the signatures on the certificate may be a facsimile. In case any officer, Transfer Agent, or Registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, Transfer Agent, or Registrar before such certificate is issued, it may be issued by the Corporation with the same effect as if such person were an officer, Transfer Agent, or Registrar at the date of issue. Shares of the Corporation’s capital stock may also be evidenced by registration in the holder’s name in uncertificated, book-entry form on the books of the Corporation in accordance with a direct registration system approved by the Securities and Exchange Commission and by the New York Stock Exchange or any securities exchange on which the stock of the Corporation may from time to time be traded.

Transfers of shares of stock of the Corporation shall be made by the Transfer Agent and Registrar on the books of the Corporation after receipt of a request with proper evidence of succession, assignment, or authority to transfer by the record holder of such stock, or by an attorney lawfully constituted in writing, and in the case of stock represented by a certificate, upon surrender of the certificate. 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 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 (or uncertificated shares in lieu of a new certificate) may be issued of the same tenor and for the same number of shares as the one alleged to have been lost, stolen, mislaid, or destroyed.

Article V.
AMENDMENTS.

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

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

Exhibit 3.2

Bylaws
of
Pacific Gas and Electric Company
amended as of June 21, 2006

Article I.
SHAREHOLDERS.

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

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

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

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

At an annual meeting of shareholders, only such business shall be conducted as shall have been properly brought before the annual meeting. To be properly brought before an annual meeting, business must be (i) specified in the notice of the annual meeting (or any supplement thereto) given by or at the direction of the Board, or (ii) otherwise properly brought before the annual meeting by a shareholder. For business to be properly brought before an annual meeting by a shareholder, including the nomination of any person (other than a person nominated by or at the direction of the Board) for election to the Board, the shareholder must have given timely and proper written notice to the Corporate Secretary of the Corporation. To be timely, the shareholder's written notice must be received at the principal executive office of the Corporation not less than forty-five days before the date corresponding to the mailing date of the notice and proxy materials for the prior year's annual meeting of shareholders; provided, however, that if the annual meeting to which the shareholder's written notice relates is to be held on a date that differs by more than thirty days from the date of the last annual meeting of shareholders, the shareholder's written notice to be timely must be so received not later than the close of business on the tenth day following the date on which public disclosure of the date of the annual meeting is made or given to shareholders. Any shareholder’s written notice that is delivered after the close of business (5:00 p.m. local time) will be considered received on the following business day. To be proper, the shareholder’s written notice must set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting, (b) the name and address of the shareholder as they appear on the Corporation’s books, (c) the class and number of shares of the Corporation that are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. In addition, if the shareholder’s written notice relates to the nomination at the annual meeting of any person for election to the Board, such notice to be proper must also set forth (a) the name, age, business address, and residence address of each person to be so nominated, (b) the principal occupation or employment of each such person, (c) the number of shares of capital stock of the Corporation beneficially owned by each such person, and (d) such other information concerning each such person as would be required under the rules of the Securities and Exchange Commission in a proxy statement soliciting proxies for the election of such person as a Director, and must be accompanied by a consent, signed by each such person, to serve as a Director of the Corporation if elected. Notwithstanding anything in the Bylaws to the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section .

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

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

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

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

Article II.
DIRECTORS.

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

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

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

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

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

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

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

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

Article III.
OFFICERS.

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

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

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

the Executive Committee. The Vice Chairman of the Board shall have authority to sign on behalf of the Corporation agreements and instruments of every character.

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

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

6. **Vice Presidents.** Each Vice President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Vice Chairman of the Board, the President, or the Bylaws. Each Vice President's authority to sign agreements and instruments on behalf of the Corporation shall be as prescribed by the Board of Directors. The Board of Directors of this company, the Chairman of the Board of this company, the Vice Chairman of the Board of this company, or the Chief Executive Officer of PG&E Corporation 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 depositaries 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. **Certificates; Direct Registration System.** Shares of the Corporation's stock may be certificated or uncertificated, as provided under California law. Any certificates that are issued shall be signed in the name of the Corporation by the Chairman of the Board, the Vice Chairman of the Board, the President, or a Vice President and by the Chief Financial Officer, an Assistant Treasurer, the Corporate Secretary, or an Assistant Secretary, certifying the number of shares and the class or series of shares owned by the shareholder. Any or all of the signatures on the certificate may be a facsimile. In case any officer, Transfer Agent, or Registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, Transfer Agent, or Registrar before such certificate is issued, it may be issued by the Corporation with the same effect as if such person were an officer, Transfer Agent, or Registrar at the date of issue. Shares of the Corporation’s capital stock may also be evidenced by registration in the holder’s name in uncertificated, book-entry form on the books of the Corporation in accordance with a direct registration system approved by the Securities and Exchange Commission and by the American Stock Exchange or any securities exchange on which the stock of the Corporation may from time to time be traded.

Transfers of shares of stock of the Corporation shall be made by the Transfer Agent and Registrar on the books of the Corporation only after receipt of a request with proper evidence of succession, assignment, or authority to transfer by the record holder of such stock, or by an attorney lawfully constituted in writing, and in the case of stock represented by a certificate, upon surrender of the certificate. 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 (or uncertificated shares in lieu of 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 PER COMMON SHARE

(in millions, except share amounts)	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Net income	$ 232	$ 267	$ 446	$ 485
Less: distributed earnings to common shareholders	115	112	229	223
Undistributed earnings	$ 117	$ 155	$ 217	$ 262
Common shareholders earnings				
Basic				
Distributed earnings to common shareholders	$ 115	$ 112	$ 229	$ 223
Undistributed earnings allocated to common shareholders	111	147	206	249
Total common shareholders earnings, basic	**$ 226**	**$ 259**	**$ 435**	**$ 472**
Diluted				
Distributed earnings to common shareholders	$ 115	$ 112	$ 229	$ 223
Undistributed earnings allocated to common shareholders	111	148	206	250
Total common shareholders earnings, diluted	**$ 226**	**$ 260**	**$ 435**	**$ 473**
Weighted average common shares outstanding, basic	**346**	**370**	**345**	**379**
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, basic	365	389	364	398
Weighted average common shares outstanding, basic	346	370	345	379
Employee share-based compensation and accelerated share repurchase program (1)	3	4	4	4
Weighted average common shares outstanding, diluted (2)	**349**	**374**	**349**	**383**
9.50% Convertible Subordinated Notes	19	19	19	19
Weighted average common shares outstanding and participating securities, diluted	368	393	368	402
Net earnings per common share, basic				
Distributed earnings, basic	$ 0.33	$ 0.30	$ 0.66	$ 0.59
Undistributed earnings, basic	0.32	0.40	0.60	0.66
Total	**$ 0.65**	**$ 0.70**	**$ 1.26**	**$ 1.25**
Net earnings per common share, diluted				
Distributed earnings, diluted	$ 0.33	$ 0.30	$ 0.66	$ 0.58
Undistributed earnings, diluted	0.32	0.40	0.59	0.65
Total	**$ 0.65**	**$ 0.70**	**$ 1.25**	**$ 1.23**

(1) Includes approximately 1 million and 2 million shares treated as outstanding in connection with the accelerated share repurchase program for the three and six months ended June 30, 2006 respectively. The remaining approximately 2 million shares relate to share-based compensation and are deemed to be outstanding per SFAS No. 128 for the purpose of calculating EPS for the three and six months ended June 30, 2006.

(2) Options to purchase PG&E Corporation common shares of 6,500 for the three months ended June 30, 2005 and 4,650 and 6,500 for the six months ended June 30, 2006 and June 30, 2005, respectively, were outstanding, but not included in the computation of diluted EPS because the option exercise prices were greater than the average market price. All options to purchase PG&E Corporation common shares for the three months ended June 30, 2006 have option exercise prices lower than the average market price and are included in the computation of diluted

EPS.

EXHIBIT 12.1
PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended June 30,	Six Months Ended June 30,	Year Ended December 31,				
	2006	2006	2005	2004	2003	2002	2001
Earnings:							
Net income	$ 231	$ 448	$ 934	$ 3,982	$ 923	$ 1,819	$ 1,015
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	-	-	-	-	-	-	-
Income taxes provision	141	273	574	2,561	528	1,178	596
Net fixed charges	171	334	589	671	964	1,029	1,019
Total Earnings	$ 543	$ 1,055	$ 2,097	$ 7,214	$ 2,415	$ 4,026	$ 2,630
Fixed Charges:							
Interest on short-term borrowings and long-term debt, net	$ 166	$ 324	$ 573	$ 682	$ 947	$ 996	$ 981
Interest on capital leases	-	-	1	1	1	2	2
AFUDC debt	5	10	15	(12)	16	21	12
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-	10	24
Total Fixed Charges	$ 171	$ 334	$ 589	$ 671	$ 964	$ 1,029	$ 1,019
Ratios of Earnings to Fixed Charges	3.18	3.16	3.56	10.75	2.51	3.91	2.58

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust.

EXHIBIT 12.2
PACIFIC GAS AND ELECTRIC COMPANY
COMPUTATION OF RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	Three Months Ended June 30, 2006	Six Months Ended June 30, 2006	Year Ended December 31, 2005	2004	2003	2002	2001
Earnings:							
Net income	$ 231	$ 448	$ 934	$ 3,982	$ 923	$ 1,819	$ 1,015
Adjustments for minority interest in losses of less than 100% owned affiliates and the Company's equity in undistributed income (losses) of less than 50% owned affiliates	-	-	-	-	-	-	-
Income taxes provision	141	273	574	2,561	528	1,178	596
Net fixed charges	171	334	589	671	964	1,029	1,019
Total Earnings	$ 543	$ 1,055	$ 2,097	$ 7,214	$ 2,415	$ 4,026	$ 2,630
Fixed Charges:							
Interest on short-term borrowings and long-term debt, net	$ 166	$ 324	$ 573	$ 682	$ 947	$ 996	$ 981
Interest on capital leases	-	-	1	1	1	2	2
AFUDC debt	5	10	15	(12)	16	21	12
Earnings required to cover the preferred stock dividend and preferred security distribution requirements of majority owned trust	-	-	-	-	-	10	24
Total Fixed Charges	171	334	589	671	964	1,029	1,019
Preferred Stock Dividends:							
Tax deductible dividends	3	6	12	9	9	9	9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	2	2	13	34	27	28	27
Total Preferred Stock Dividends	5	8	25	43	36	37	36
Total Combined Fixed Charges and Preferred Stock Dividends	$ 176	$ 342	$ 614	$ 714	$ 1,000	$ 1,066	$ 1,055
Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends	3.09	3.08	3.42	10.10	2.42	3.78	2.49

Note:

For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the minority interest in losses of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements and preferred security distribution requirements of majority-owned trust. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities.

Exhibit 31.1

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Peter A. Darbee, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2006 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2006

/s/ Peter A. Darbee

Peter A. Darbee

Chairman, Chief Executive Officer and President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Christopher P. Johns, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2006 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2006

/s/ Christopher P. Johns

Christopher P. Johns

Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 31.2

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Thomas B. King, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2006 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2006

/s/ Thomas B. King

Thomas B. King

President and Chief Executive Officer

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Christopher P. Johns, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the year ended June 30, 2006 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2006

/s/ Christopher P. Johns

Christopher P. Johns

Senior Vice President, Chief Financial Officer and Treasurer

Exhibit 32.1

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 June 30, 2006, I, Peter A. Darbee, 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 June 30, 2006, 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 June 30, 2006, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

/s/ Peter A. Darbee
PETER A. DARBEE
Chairman, Chief Executive Officer and President

August 2, 2006

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 June 30, 2006, I, Christopher P. Johns, Senior Vice President, Chief Financial Officer and Treasurer 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 June 30, 2006, 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 June 30, 2006, fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

/s/ Christopher P. Johns
CHRISTOPHER P. JOHNS
Senior Vice President,
Chief Financial Officer and Treasurer

August 2, 2006

Exhibit 32.2

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 June 30, 2006, I, Thomas B. King, 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 June 30, 2006, 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 June 30, 2006, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

/s/ Thomas B. King
THOMAS B. KING
President and Chief Executive Officer

August 2, 2006

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 June 30, 2006, I, Christopher P. Johns, 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 June 30, 2006, 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 June 30, 2006, fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

/s/ Christopher P. Johns
CHRISTOPHER P. JOHNS
Senior Vice President, Chief Financial Officer
and Treasurer

August 2, 2006