

PG&E CORP

FORM 10-Q (Quarterly Report)

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

(Mark One)

☒

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

For the quarterly period ended March 31, 2011

OR

☐

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

For the transition period from _____ to _____

Commission File Number	Exact Name of Registrant as specified in its charter	State or other Jurisdiction of Incorporation	IRS Employer Identification Number
1-12609	PG&E Corporation	California	94-3234914
1-2348	Pacific Gas and Electric Company	California	94-0742640
Pacific Gas and Electric Company 77 Beale Street P.O. Box 770000 San Francisco, California 94177		PG&E Corporation One Market, Spear Tower Suite 2400 San Francisco, California 94105	
Address of principal executive offices, including zip code			
Pacific Gas and Electric Company (415) 973-7000		PG&E Corporation (415) 267-7000	
Registrant's telephone number, including area code			

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

PG&E Corporation ☒ Yes ☐ No

Pacific Gas and Electric Company: ☐ Yes ☐ No

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

PG&E Corporation:	☒ Large accelerated filer	☐ Accelerated Filer
	☐ Non-accelerated filer	☐ Smaller reporting company
Pacific Gas and Electric Company:	☐ Large accelerated filer	☐ Accelerated Filer
	☒ Non-accelerated filer	☐ Smaller reporting company

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 ☒ No

Pacific Gas and Electric Company: ☐ Yes ☒ 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 April 25, 2011:

PG&E Corporation	397,949,716
Pacific Gas and Electric Company	264,374,809

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**PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2011
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PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(in millions, except per share amounts)	(Unaudited)	
	Three Months Ended	
	March 31,	
	2011	2010
Operating Revenues		
Electric	\$ 2,617	\$ 2,510
Natural gas	980	965
Total operating revenues	3,597	3,475
Operating Expenses		
Cost of electricity	888	920
Cost of natural gas	508	495
Operating and maintenance	1,226	991
Depreciation, amortization, and decommissioning	491	451
Total operating expenses	3,113	2,857
Operating Income	484	618
Interest income	2	2
Interest expense	(177)	(168)
Other income (expense), net	17	(6)
Income Before Income Taxes	326	446
Income tax provision	124	185
Net Income	202	261
Preferred stock dividend requirement of subsidiary	3	3
Income Available for Common Shareholders	\$ 199	\$ 258
Weighted Average Common Shares Outstanding, Basic	396	371
Weighted Average Common Shares Outstanding, Diluted	397	389
Net Earnings Per Common Share, Basic	\$ 0.50	\$ 0.69
Net Earnings Per Common Share, Diluted	\$ 0.50	\$ 0.67
Dividends Declared Per Common Share	\$ 0.46	\$ 0.46

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
	March 31,	December 31,
(in millions)	2011	2010
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 240	\$ 291
Restricted cash (\$35 and \$38 related to energy recovery bonds at March 31, 2011 and December 31, 2010, respectively)	431	563
Accounts receivable		
Customers (net of allowance for doubtful accounts of \$85 and \$81 at March 31, 2011 and December 31, 2010, respectively)	922	944
Accrued unbilled revenue	616	649
Regulatory balancing accounts	1,293	1,105
Other	814	794
Regulatory assets	580	599
Inventories		
Gas stored underground and fuel oil	78	152
Materials and supplies	214	205
Income taxes receivable	35	47
Other	248	193
Total current assets	5,471	5,542
Property, Plant, and Equipment		
Electric	34,068	33,508
Gas	11,482	11,382
Construction work in progress	1,369	1,384
Other	14	15
Total property, plant, and equipment	46,933	46,289
Accumulated depreciation	(15,061)	(14,840)
Net property, plant, and equipment	31,872	31,449
Other Noncurrent Assets		
Regulatory assets (\$645 and \$735 related to energy recovery bonds at March 31, 2011 and December 31, 2010, respectively)	5,655	5,846
Nuclear decommissioning trusts	2,054	2,009
Income taxes receivable	566	565
Other	641	614
Total other noncurrent assets	8,916	9,034
TOTAL ASSETS	\$ 46,259	\$ 46,025

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	(Unaudited) Balance At	
	March 31, 2011	December 31, 2010
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	\$ 1,288	\$ 853
Long-term debt, classified as current	922	809
Energy recovery bonds, classified as current	409	404
Accounts payable		
Trade creditors	974	1,129
Disputed claims and customer refunds	691	745
Regulatory balancing accounts	531	256
Other	520	379
Interest payable	784	862
Income taxes payable	128	77
Deferred income taxes	79	113
Other	1,446	1,558
Total current liabilities	7,772	7,185
Noncurrent Liabilities		
Long-term debt	10,294	10,906
Energy recovery bonds	321	423
Regulatory liabilities	4,584	4,525
Pension and other postretirement benefits	2,288	2,234
Asset retirement obligations	1,583	1,586
Deferred income taxes	5,721	5,547
Other	2,030	2,085
Total noncurrent liabilities	26,821	27,306
Commitments and Contingencies (Note 10)		
Equity		
Shareholders' Equity		
Preferred stock	-	-
Common stock, no par value, authorized 800,000,000 shares, 397,453,525 shares outstanding at March 31, 2011 and 395,227,205 shares outstanding at December 31, 2010	6,983	6,878
Reinvested earnings	4,624	4,606
Accumulated other comprehensive loss	(193)	(202)
Total shareholders' equity	11,414	11,282
Noncontrolling Interest – Preferred Stock of Subsidiary	252	252
Total equity	11,666	11,534
TOTAL LIABILITIES AND EQUITY	\$ 46,259	\$ 46,025

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Three Months Ended March 31,	
	2011	2010
Cash Flows from Operating Activities		
Net income	\$ 202	\$ 261
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	550	506
Allowance for equity funds used during construction	(20)	(28)
Deferred income taxes and tax credits, net	99	137
Other	(15)	26
Effect of changes in operating assets and liabilities:		
Accounts receivable	35	114
Inventories	65	59
Accounts payable	182	87
Income taxes receivable/payable	34	69
Other current assets and liabilities	(205)	(319)
Regulatory assets, liabilities, and balancing accounts, net	(10)	(376)
Other noncurrent assets and liabilities	171	(141)
Net cash provided by operating activities	1,088	395
Cash Flows from Investing Activities		
Capital expenditures	(945)	(855)
Decrease in restricted cash	132	4
Proceeds from sales and maturities of nuclear decommissioning trust investments	726	337
Purchases of nuclear decommissioning trust investments	(735)	(343)
Other	(61)	9
Net cash used in investing activities	(883)	(848)
Cash Flows from Financing Activities		
Net issuances of commercial paper, net of discount of \$1 in 2011	415	418
Long-term debt matured	(500)	-
Energy recovery bonds matured	(97)	(93)
Common stock issued	82	10
Common stock dividends paid	(174)	(157)
Other	18	6
Net cash provided by (used in) financing activities	(256)	184
Net change in cash and cash equivalents	(51)	(269)
Cash and cash equivalents at January 1	291	527
Cash and cash equivalents at March 31	\$ 240	\$ 258
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest, net of amounts capitalized	\$ (215)	\$ (193)
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	\$ 181	\$ 169
Capital expenditures financed through accounts payable	174	215
Noncash common stock issuances	6	-

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(in millions)	(Unaudited)	
	Three Months Ended March 31,	
	2011	2010
Operating Revenues		
Electric	\$ 2,616	\$ 2,510
Natural gas	980	965
Total operating revenues	3,596	3,475
Operating Expenses		
Cost of electricity	888	920
Cost of natural gas	508	495
Operating and maintenance	1,226	990
Depreciation, amortization, and decommissioning	490	451
Total operating expenses	3,112	2,856
Operating Income	484	619
Interest income	2	2
Interest expense	(171)	(156)
Other income (expense), net	17	(6)
Income Before Income Taxes	332	459
Income tax provision	131	195
Net Income	201	264
Preferred stock dividend requirement	3	3
Income Available for Common Stock	\$ 198	\$ 261

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited) Balance At	
	March 31, 2011	December 31, 2010
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 52	\$ 51
Restricted cash (\$35 and \$38 related to energy recovery bonds at March 31, 2011 and December 31, 2010, respectively)	431	563
Accounts receivable		
Customers (net of allowance for doubtful accounts of \$85 and \$81 at March 31, 2011 and December 31, 2010, respectively)	922	944
Accrued unbilled revenue	616	649
Regulatory balancing accounts	1,293	1,105
Other	842	856
Regulatory assets	580	599
Inventories		
Gas stored underground and fuel oil	78	152
Materials and supplies	214	205
Income taxes receivable	43	48
Other	243	190
Total current assets	5,314	5,362
Property, Plant, and Equipment		
Electric	34,068	33,508
Gas	11,482	11,382
Construction work in progress	1,369	1,384
Total property, plant, and equipment	46,919	46,274
Accumulated depreciation	(15,047)	(14,826)
Net property, plant, and equipment	31,872	31,448
Other Noncurrent Assets		
Regulatory assets (\$645 and \$735 related to energy recovery bonds at March 31, 2011 and December 31, 2010, respectively)	5,655	5,846
Nuclear decommissioning trusts	2,054	2,009
Income taxes receivable	614	614
Other	364	400
Total other noncurrent assets	8,687	8,869
TOTAL ASSETS	\$ 45,873	\$ 45,679

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	(Unaudited) Balance At	
	March 31, 2011	December 31, 2010
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 1,288	\$ 853
Long-term debt, classified as current	922	809
Energy recovery bonds, classified as current	409	404
Accounts payable		
Trade creditors	974	1,129
Disputed claims and customer refunds	691	745
Regulatory balancing accounts	531	256
Other	539	390
Interest payable	774	857
Income taxes payable	137	116
Deferred income taxes	87	118
Other	1,249	1,349
Total current liabilities	7,601	7,026
Noncurrent Liabilities		
Long-term debt	9,945	10,557
Energy recovery bonds	321	423
Regulatory liabilities	4,584	4,525
Pension and other postretirement benefits	2,227	2,174
Asset retirement obligations	1,583	1,586
Deferred income taxes	5,833	5,659
Other	1,965	2,008
Total noncurrent liabilities	26,458	26,932
Commitments and Contingencies (Note 10)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, \$5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at March 31, 2011 and December 31, 2010	1,322	1,322
Additional paid-in capital	3,306	3,241
Reinvested earnings	7,114	7,095
Accumulated other comprehensive loss	(186)	(195)
Total shareholders' equity	11,814	11,721
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 45,873	\$ 45,679

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions)	(Unaudited)	
	Three Months Ended March 31,	
	2011	2010
Cash Flows from Operating Activities		
Net income	\$ 201	\$ 264
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	534	491
Allowance for equity funds used during construction	(20)	(28)
Deferred income taxes and tax credits, net	99	138
Other	(15)	26
Effect of changes in operating assets and liabilities:		
Accounts receivable	69	114
Inventories	65	59
Accounts payable	190	94
Income taxes receivable/payable	34	77
Other current assets and liabilities	(196)	(325)
Regulatory assets, liabilities, and balancing accounts, net	(10)	(376)
Other noncurrent assets and liabilities	144	(126)
Net cash provided by operating activities	1,095	408
Cash Flows from Investing Activities		
Capital expenditures	(945)	(855)
Decrease in restricted cash	132	4
Proceeds from sales and maturities of nuclear decommissioning trust investments	726	337
Purchases of nuclear decommissioning trust investments	(735)	(343)
Other	7	5
Net cash used in investing activities	(815)	(852)
Cash Flows from Financing Activities		
Net issuances of commercial paper, net of discount of \$1 in 2011	415	418
Long-term debt matured	(500)	-
Energy recovery bonds matured	(97)	(93)
Preferred stock dividends paid	(4)	(4)
Common stock dividends paid	(179)	(179)
Equity contribution	65	20
Other	21	8
Net cash provided by (used in) financing activities	(279)	170
Net change in cash and cash equivalents	1	(274)
Cash and cash equivalents at January 1	51	334
Cash and cash equivalents at March 31	\$52	\$60
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest, net of amounts capitalized	\$ (215)	\$ (193)
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	\$ 174	\$ 215

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)**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. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company (“Utility”), a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is regulated by the California Public Utilities Commission (“CPUC”) and the Federal Energy Regulatory Commission (“FERC”). The Utility’s accounts for electric and gas operations are maintained in accordance with the Uniform System of Accounts prescribed by the FERC.

This quarterly report on Form 10-Q is a combined report of PG&E Corporation and the Utility that includes separate Condensed Consolidated Financial Statements for each company. The Notes to the 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 the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated from the Condensed Consolidated Financial Statements.

The accompanying Condensed Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in the United States of America (“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 (“SEC”) and therefore do not contain all of the information and footnotes required by GAAP and the SEC for annual financial statements. PG&E Corporation’s and the Utility’s Condensed Consolidated Financial Statements reflect all adjustments (consisting only of normal recurring adjustments) that management believes are necessary for the fair presentation of their financial condition, results of operations, and cash flows for the periods presented. The information at December 31, 2010 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 2010 Annual Report on Form 10-K filed with the SEC on February 17, 2011. PG&E Corporation’s and the Utility’s combined 2010 Annual Report on Form 10-K, together with the information incorporated by reference into such report, is referred to in this quarterly report as the “2010 Annual Report.” This quarterly report should be read in conjunction with the 2010 Annual Report.

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions based on a wide range of factors, including future regulatory decisions and economic conditions that are difficult to predict. Some of the more critical estimates and assumptions relate to the Utility’s regulatory assets and liabilities, loss contingencies associated with environmental remediation and legal matters, asset retirement obligations (“ARO”s), and pension plan and other postretirement plan obligations. Management believes that its estimates and assumptions reflected in the Condensed Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used by PG&E Corporation and the Utility are discussed in Notes 1 and 2 of the Notes to the Consolidated Financial Statements in the 2010 Annual Report. Any significant changes to those policies or new significant policies are described below.

Pension and Other Postretirement Benefits

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

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The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Statements of Income for the three months ended March 31, 2011 and 2010 were as follows:

(in millions)	Pension Benefits		Other Benefits	
	Three Months Ended		Three Months Ended	
	March 31,		March 31,	
	2011	2010	2011	2010
Service cost for benefits earned	\$ 82	\$ 69	\$ 11	\$ 10
Interest cost	164	161	23	23
Expected return on plan assets	(167)	(156)	(20)	(18)
Amortization of transition obligation	-	-	6	6
Amortization of prior service cost	9	13	6	6
Amortization of unrecognized loss	12	11	1	1
Net periodic benefit cost	100	98	27	28
Less: transfer to regulatory account ⁽¹⁾	(36)	(58)	-	-
Total	\$ 64	\$ 40	\$ 27	\$ 28

⁽¹⁾ The Utility recorded \$36 million and \$58 million for the three month periods ended March 31, 2011 and 2010, respectively, to a regulatory account as the amounts are probable of recovery from customers in future rates.

There was no material difference between PG&E Corporation's and the Utility's consolidated net periodic benefit costs for the three months ended March 31, 2011 and 2010.

Variable Interest Entities

The Utility has contracts to purchase energy and capacity from variable interest entities ("VIEs"). The Utility evaluated these contracts and determined that it either does not have a variable interest in the VIE or it is not the primary beneficiary of the VIE where a variable interest exists. The determination of whether the Utility has a variable interest in a VIE includes an analysis of the impact the power purchase agreement has on the variability in the VIE's gross margin. The primary beneficiary determination considers which entity has the power to direct the activities of the VIE most significant to the VIE's economic performance, and may include any decision-making rights associated with designing the VIE, dispatch rights, operating and maintenance activities, and re-marketing activities of the power plant after the end of the power purchase agreement with the Utility. The Utility's financial exposure is limited to the amount it pays for delivered electricity and capacity and the Utility has not provided any other support to these VIEs. (See Note 10 below.)

The Utility was the primary beneficiary of PG&E Energy Recovery Funding LLC ("PERF") at March 31, 2011, and consolidated PERF. The Utility is exposed to PERF's losses and returns through the Utility's 100% equity investment in PERF and the Utility was involved in the design of PERF, which was an activity that was significant to PERF's economic performance. The assets of PERF were \$799 million at March 31, 2011 and primarily consisted of assets related to energy recovery bonds ("ERBs"), which are included in other noncurrent assets – regulatory assets in the Condensed Consolidated Balance Sheets. The liabilities of PERF were \$730 million at March 31, 2011 and consisted of energy recovery bonds, which are included in current and noncurrent liabilities in the Condensed Consolidated Balance Sheets. (See Note 4 below.) The assets of PERF are only available to settle the liabilities of PERF and PERF's creditors have no recourse to the Utility.

As of March 31, 2011, PG&E Corporation's affiliates had entered into four tax equity agreements with two privately held companies to fund residential and commercial retail solar energy installations. Under these agreements, PG&E Corporation agreed to provide lease payments and investment contributions of up to \$300 million to these companies in exchange for the right to receive the benefits from local rebates, federal investment tax credits or grants, and a share of the customer payments made to these companies. As of March 31, 2011, PG&E Corporation had made total payments of \$216 million under these tax equity agreements. These amounts are recorded in other noncurrent assets – other in PG&E Corporation's Condensed Consolidated Balance Sheets. PG&E Corporation holds a variable interest in these companies as a result of these agreements. PG&E Corporation was not the primary beneficiary of, and did not consolidate any of these companies at March 31, 2011. In making this determination, PG&E Corporation evaluated which party has control over these companies' significant economic activities such as designing the companies, vendor selection, construction, customer selection, and re-marketing activities at the end of customer leases, and determined that these activities are under the control of these companies.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

As a regulated entity, the Utility's rates are designed to recover the costs of providing service. The Utility capitalizes and records, as a regulatory asset, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods that the costs are expected to be recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. In addition, amounts that are probable of being credited or refunded to customers in the future are recorded as regulatory liabilities.

The Utility uses regulatory balancing accounts to accumulate differences between actual billed and unbilled revenues and the Utility's authorized revenue requirements for the period. The Utility also uses regulatory balancing accounts to accumulate differences between incurred costs and actual billed and unbilled revenues, as well as differences between incurred costs and authorized revenue meant to recover those costs. Under-collections that are probable of recovery through regulated rates are recorded as regulatory balancing account assets. Over-collections that are probable of being refunded to customers are recorded as regulatory balancing account liabilities.

Regulatory Assets

Current Regulatory Assets

At March 31, 2011 and December 31, 2010, the Utility had current regulatory assets of \$580 million and \$599 million, respectively, consisting primarily of price risk management regulatory assets and the Utility's retained generation regulatory assets. The current portion of price risk management regulatory assets represents the deferral of unrealized losses related to price risk management derivative instruments with terms of one year or less. (See Note 7 below.) The current portion of the Utility's retained generation regulatory assets represents one year of amortization of these regulatory assets over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.

Long-Term Regulatory Assets

Long-term regulatory assets are composed of the following:

(in millions)	Balance at	
	March 31, 2011	December 31, 2010
Pension benefits	\$ 1,775	\$ 1,759
Deferred income taxes	1,285	1,250
Utility retained generation	649	666
Energy recovery bonds	645	735
Environmental compliance costs	412	450
Price risk management	331	424
Unamortized loss, net of gain, on reacquired debt	175	181
Other	383	381
Total long-term regulatory assets	\$ 5,655	\$ 5,846

The regulatory asset for pension benefits represents the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized in accordance with GAAP, which also includes amounts that otherwise would be fully recorded to accumulated other comprehensive loss in the Condensed Consolidated Balance Sheets. (See Note 12 of the Notes to the Consolidated Financial Statements in the 2010 Annual Report.)

The regulatory assets for deferred income taxes represent deferred income tax benefits previously passed through to customers. The CPUC requires the Utility to pass through certain tax benefits to customers by reducing rates, thereby ignoring the effect of deferred taxes on rates. Based on current regulatory ratemaking and income tax laws, the Utility expects to recover these regulatory assets over average plant depreciation lives of 1 to 45 years.

In connection with the settlement agreement entered into between PG&E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code ("Chapter 11 Settlement Agreement"), the CPUC authorized the Utility to recover \$1.2 billion of costs related to the Utility's retained generation assets. The individual components of these regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized. The weighted average remaining life of the assets is 13 years.

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The regulatory asset for ERBs represents the refinancing of the regulatory asset provided for in the Chapter 11 Settlement Agreement. (See Note 4 below.) The regulatory asset is amortized over the life of the bonds, consistent with the period over which the related revenues and bond-related expenses are recognized. The Utility expects to fully recover this asset by the end of 2012 when the ERBs mature.

The regulatory assets for environmental compliance costs represent estimated environmental compliance costs that the Utility expects to recover in future rates as actual environmental compliance costs are incurred. The Utility expects to recover these costs over the next 32 years. (See Note 10 below.)

Price risk management regulatory assets represent the deferral of unrealized losses related to price risk management derivative instruments with terms in excess of one year. (See Note 7 below.)

The regulatory assets for unamortized loss, net of gain, on reacquired debt represent 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 next 16 years, which is the remaining amortization period of the reacquired debt. The Utility expects to fully recover these costs by 2026.

At March 31, 2011 and December 31, 2010, “other” primarily consisted of regulatory assets relating to ARO expenses for decommissioning of the Utility’s fossil-fuel generation facilities that are probable of future recovery through the ratemaking process; costs that the Utility incurred in terminating a 30-year power purchase agreement which are being amortized and collected in rates through September 2014; costs incurred in relation to the Utility’s plan of reorganization under Chapter 11 that became effective in April 2004; and removal costs associated with the replacement of old electromechanical meters with SmartMeter™ devices.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its retained generation regulatory assets and regulatory assets for unamortized loss, net of gain, on reacquired debt.

Regulatory Liabilities

Current Regulatory Liabilities

At March 31, 2011 and December 31, 2010, the Utility had current regulatory liabilities of \$79 million and \$81 million, respectively, primarily consisting of amounts that the Utility expects to refund to customers for over-collected electric transmission rates and amounts that the Utility expects to refund to electric transmission customers for their portion of settlements the Utility entered into with various electricity suppliers to resolve certain remaining Chapter 11 disputed claims. Current regulatory liabilities are included in current liabilities – other in the Condensed Consolidated Balance Sheets.

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

(in millions)	Balance at	
	March 31, 2011	December 31, 2010
Cost of removal obligation	\$ 3,296	\$ 3,229
Recoveries in excess of ARO	643	600
Public purpose programs	503	573
Other	142	123
Total long-term regulatory liabilities	\$ 4,584	\$ 4,525

The regulatory liability for the Utility’s cost of removal obligations represents differences between amounts collected in rates for asset removal costs and the asset removal costs recorded in accordance with GAAP.

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The regulatory liability for recoveries in excess of ARO represents differences between ARO expenses recorded in accordance with GAAP and amounts collected in rates for the decommissioning of the Utility's nuclear power facilities. Decommissioning costs recovered in rates are placed in nuclear decommissioning trusts. The regulatory liability for recoveries in excess of ARO also represents the deferral of realized and unrealized gains and losses on those nuclear decommissioning trust assets.

The regulatory liability for public purpose programs represents amounts received from customers designated for public purpose program costs that are expected to be incurred in the future. The public purpose programs regulatory liabilities primarily consist of revenues collected from customers to pay for costs that the Utility expects to incur in the future under energy efficiency programs designed to encourage the manufacture, design, distribution, and customer use of energy efficient appliances and other energy-using products; under the California Solar Initiative program to promote the use of solar energy in residential homes and commercial, industrial, and agricultural properties; and under the Self-Generation Incentive program to promote distributed generation technologies installed on the customer's side of the Utility meter that provide electricity and gas for all or a portion of that customer's load.

"Other" at March 31, 2011 and December 31, 2010 primarily consisted of regulatory liabilities related to the gain associated with the Utility's acquisition of the permits and other assets related to the Gateway Generating Station as part of a settlement that the Utility entered into with Mirant Corporation, insurance recoveries for hazardous substance remediation, and the price risk management regulatory liabilities representing the deferral of unrealized gains related to price risk management derivative instruments with terms in excess of one year. (See Note 7 below.).

Regulatory Balancing Accounts

The Utility's current regulatory balancing accounts represent the amounts expected to be received from or refunded to the Utility's customers through authorized rate adjustments within the next 12 months. Regulatory balancing accounts that the Utility does not expect to collect or refund in the next 12 months are included in other noncurrent assets – regulatory assets and noncurrent liabilities – regulatory liabilities in the Condensed Consolidated Balance Sheets.

Current Regulatory Balancing Accounts, net

(in millions)	Receivable (Payable)	
	Balance at	
	March 31, 2011	December 31, 2010
Utility generation	\$ 439	\$ 303
Distribution revenue adjustment mechanism	241	145
Public purpose programs	188	164
Hazardous substance	57	38
Gas fixed cost	(89)	56
Energy procurement	(91)	(25)
Energy recovery bonds	(110)	(34)
Other	127	202
Total regulatory balancing accounts, net	\$ 762	\$ 849

The utility generation balancing account is used to record and recover the authorized revenue requirements associated with Utility-owned electric generation, including capital and related non-fuel operating and maintenance expenses. The distribution revenue adjustment mechanism balancing account is used to record and recover the authorized electric distribution revenue requirements and certain other electric distribution-related authorized costs. The Utility's recovery of these revenue requirements is independent, or "decoupled," from the volume of sales; therefore, the Utility recognizes revenue evenly over the year, even though the level of cash collected from customers will fluctuate depending on the volume of electricity sales. During the colder months of winter there is generally an under-collection in these balancing accounts due to lower electricity sales and lower rates. During the warmer months of summer there is generally an over-collection due to higher electricity sales and higher rates.

The public purpose programs balancing accounts are primarily used to track the recovery of the authorized public purpose program revenue requirements and incentive awards earned by the Utility for implementing customer energy efficiency programs. The public purpose programs primarily consist of the energy efficiency programs; low-income energy efficiency programs; research, development, and demonstration programs; and renewable energy programs.

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The hazardous substance balancing accounts are used to track recoverable hazardous substance clean up costs through the CPUC-approved ratemaking mechanism that authorizes the Utility to recover 90% of hazardous waste remediation costs. The current balance represents eligible remediation costs incurred by the Utility during 2010 that will be recovered through an annual true-up filing with the CPUC in January 2012. (See Note 10 below.)

The gas fixed cost balancing account is used to track the recovery of CPUC-authorized gas distribution revenue requirements and certain other gas distribution-related costs. Similar to the utility generation and the distribution revenue adjustment mechanism balancing accounts discussed above, the Utility's recovery of these revenue requirements is decoupled from the volume of sales. During the colder months of winter there is generally an over-collection in this balancing account due to higher natural gas sales. During the warmer months of summer there is generally an under-collection due to lower natural gas sales.

The Utility is generally authorized to recover 100% of its prudently incurred electric fuel and energy procurement costs. The Utility tracks energy procurement costs in balancing accounts and files annual forecasts of energy procurement costs that it expects to incur during the following year. The Utility's electric rates are set to recover such expected costs.

The ERB balancing account records the benefits and costs associated with ERBs that are provided to, or received from, customers. This account ensures that customers receive the benefits of the net amount of energy supplier refunds, claim offsets, and other credits received by the Utility after the second series of ERBs was issued.

At March 31, 2011 and December 31, 2010, "other" primarily consisted of balancing accounts that track recovery of the authorized revenue requirements and costs related to the SmartMeter™ advanced metering project.

NOTE 4: DEBT

PG&E Corporation

Credit Facility

At March 31, 2011, PG&E Corporation had no cash borrowings outstanding under its \$187 million revolving credit facility.

Utility

Credit Facilities

At March 31, 2011, the Utility had no cash borrowings outstanding under its \$1.9 billion and \$750 million revolving credit facilities.

At March 31, 2011, the Utility had \$315 million of letters of credit outstanding under its \$1.9 billion revolving credit facility.

The Utility's revolving credit facilities also provide liquidity support for commercial paper offerings. At March 31, 2011, the Utility had \$1.0 billion of commercial paper outstanding at an average yield of 0.39%.

Other Short-term Borrowings

At March 31, 2011, the interest rate on the Utility's \$250 million principal amount of Floating Rate Senior Notes, due October 11, 2011, was 0.88%. The interest rate for the Floating Rate Senior Notes is equal to the three-month LIBOR plus 0.58% and resets quarterly. On April 11, 2011, the interest rate was reset to 0.87%.

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 dedicated rate component to be collected from the Utility's electricity customers. The total amount of ERB principal outstanding was \$730 million at March 31, 2011.

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While PERF is a wholly owned subsidiary of the Utility, it is legally separate from the Utility. The assets (including the recovery property) of PERF 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: EQUITY

PG&E Corporation's and the Utility's changes in equity for the three months ended March 31, 2011 were as follows:

(in millions)	PG&E Corporation	Utility
	Total Equity	Shareholders' Equity
Balance at December 31, 2010	\$ 11,534	\$ 11,721
Net income	202	201
Common stock issued	88	-
Share-based compensation expense	15	-
Common stock dividends declared	(181)	(179)
Preferred stock dividend requirement	-	(3)
Preferred stock dividend requirement of subsidiary	(3)	-
Other comprehensive income	9	9
Equity contribution	-	65
Other	2	-
Balance at March 31, 2011	\$ 11,666	\$ 11,814

For the three months ended March 31, 2011, PG&E Corporation issued 2,032,223 shares of common stock upon the exercise of employee stock options and under its 401(k) plan and Dividend Reinvestment and Stock Purchase Plan.

For the three months ended March 31, 2011, PG&E Corporation contributed equity of \$65 million to the Utility in order to maintain the 52% common equity ratio authorized by the CPUC and to ensure that the Utility has adequate capital to fund its capital expenditures.

Comprehensive Income

Comprehensive income consists of net income and other comprehensive income, which includes certain changes in equity that are excluded from net income. Specifically, adjustments for employee benefit plans, net of tax, are recorded in other comprehensive income.

(in millions)	PG&E Corporation		Utility	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2011	2010	2011	2010
Net income	\$ 202	\$ 261	\$ 201	\$ 264
Employee benefit plan adjustment, net of tax ⁽¹⁾	9	(80)	9	(80)
Comprehensive Income	\$ 211	\$ 181	\$ 210	\$ 184

⁽¹⁾ These balances are net of income tax expense of \$6 million and net of income tax benefit of \$55 million for the three months ended March 31, 2011 and 2010, respectively.

NOTE 6: EARNINGS PER SHARE

For the three months ended March 31, 2011, PG&E Corporation's basic earnings per common share ("EPS") was calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. For the three months ended March 31, 2010, PG&E Corporation calculated EPS using the "two-class" method because PG&E Corporation's convertible subordinated notes that were then outstanding were considered to be participating securities under applicable accounting standards. Under the two-class method, the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders is divided by the weighted average number of common shares outstanding during the period. In applying the two-class method, undistributed earnings were allocated to both common shares and participating securities. Since all of PG&E Corporation's convertible subordinated notes have been converted into common stock there were no participating securities outstanding as of March 31, 2011.

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

(in millions, except per share amounts)	Three Months Ended March 31,	
	2011	2010
Basic		
Income Available for Common Shareholders	\$ 199	\$ 258
Less: distributed earnings to common shareholders	181	169
Undistributed earnings	<u>\$ 18</u>	<u>\$ 89</u>
Allocation of undistributed earnings to common shareholders		
Distributed earnings to common shareholders	\$ 181	\$ 169
Undistributed earnings allocated to common shareholders	18	85
Total common shareholders earnings	<u>\$ 199</u>	<u>\$ 254</u>
Weighted average common shares outstanding, basic	396	371
Convertible subordinated notes	-	16
Weighted average common shares outstanding and participating securities	<u>396</u>	<u>387</u>
Net earnings per common share, basic		
Distributed earnings, basic ⁽¹⁾	\$ 0.46	\$ 0.46
Undistributed earnings, basic	0.04	0.23
Total	<u>\$ 0.50</u>	<u>\$ 0.69</u>

⁽¹⁾ Distributed earnings, basic may differ from actual per share amounts paid as dividends, as the EPS computation under GAAP requires the use of the weighted average, rather than the actual, number of shares outstanding.

In calculating diluted EPS, PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation. During 2010, when PG&E Corporation's convertible subordinated notes were outstanding, the "if-converted" method was also applied in calculating diluted EPS to reflect the dilutive effect of the convertible subordinated notes to the extent that the impact was dilutive when compared to basic EPS. As noted above, these convertible subordinated notes were fully converted into shares of common stock in 2010 and were not outstanding during 2011.

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

(in millions, except per share amounts)	Three months ended March 31,	
	2011	2010
Diluted		
Income available for common shareholders	\$ 199	\$ 258
Add earnings impact of assumed conversion of participating securities:		
Interest expense on convertible subordinated notes, net of tax	-	4
Income available for common shareholders and assumed conversion	<u>\$ 199</u>	<u>\$ 262</u>
Weighted average common shares outstanding, basic	396	371
Add incremental shares from assumed conversions:		
Convertible subordinated notes	-	16
Employee share-based compensation	1	2
Weighted average common shares outstanding, diluted	<u>397</u>	<u>389</u>
Total earnings per common share, diluted	<u>\$ 0.50</u>	<u>\$ 0.67</u>

For each of the periods presented above, the calculation of outstanding shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

NOTE 7: DERIVATIVES AND HEDGING ACTIVITIES**Use of Derivative Instruments**

The Utility and PG&E Corporation, mainly through its ownership of the Utility, face market risk primarily related to electricity and natural gas commodity prices. All of the Utility's risk management activities involving derivatives reduce the volatility of commodity costs on behalf of its customers. The CPUC allows the Utility to charge customer rates designed to recover the Utility's reasonable costs of providing services, including the cost to obtain and deliver electricity and natural gas.

The Utility uses both derivative and non-derivative contracts in managing its customers' exposure to commodity-related price risk, including:

- forward contracts that commit the Utility to purchase a commodity in the future;
- swap agreements that require payments to or from counterparties based upon the difference between two prices for a predetermined contractual quantity; and
- option contracts that provide the Utility with the right to buy a commodity at a predetermined price.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements.

Commodity-related price risk management activities that meet the definition of a derivative are recorded at fair value on the Condensed Consolidated Balance Sheets. As long as the ratemaking mechanisms discussed above remain in place and the Utility's risk management activities are carried out in accordance with CPUC directives, the Utility expects to fully recover from customers, in rates, all costs related to commodity-related price risk-related derivative instruments. Therefore, all unrealized gains and losses associated with the change in fair value of these derivative instruments are deferred and recorded within the Utility's regulatory assets and liabilities on the Condensed Consolidated Balance Sheets. (See Note 3 above.) Net realized gains or losses on derivative instruments related to price risk for commodities are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from customers.

The Utility elects the normal purchase and sale exception for qualifying commodity-related derivative instruments. Derivative instruments that require physical delivery, are probable of physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered are eligible for the normal purchase and sale exception. The fair value of instruments that are eligible for the normal purchase and sales exception are not reflected in the Condensed Consolidated Balance Sheets.

Electricity Procurement

The Utility obtains electricity from a diverse mix of resources, including third-party power purchase agreements, amounts allocated to the Utility's customers under power purchase contracts that have been entered into by the California Department of Water Resources ("DWR"), and its own electricity generation facilities. The amount of electricity the Utility needs to procure to meet the demands of customers is subject to change for a number of reasons, including:

- periodic expirations or terminations of existing electricity purchase contracts, including the DWR's contracts;
- the execution of new electricity purchase contracts;
- the amount of electricity generated by the Utility's two nuclear generation units at the Diablo Canyon power plant ("Diablo Canyon") which can be affected by planned and unplanned outages, the availability of nuclear fuel, and regulatory or legislative actions that requires the temporary or permanent curtailment or cessation of nuclear operations;
- fluctuation in the output of hydroelectric and other renewable energy resource facilities owned or under contract;
- changes in the Utility's customers' electricity demands due to customer and economic growth or decline, weather, implementation of new energy efficiency and demand response programs, direct access, and community choice aggregation;
- the acquisition, retirement, or closure of generation facilities owned by the Utility or others; and
- changes in market prices that make it more economical to purchase power in the market rather than use the Utility's existing or contracted resources to generate power.

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The Utility enters into third-party power purchase agreements to ensure sufficient electricity to meet customer needs. The Utility's third-party power purchase agreements are generally accounted for as leases, but certain third-party power purchase agreements are considered derivative instruments. The Utility elects to use the normal purchase and sale exception for eligible derivative instruments.

A portion of the Utility's third-party power purchase agreements contain market-based pricing terms. In order to reduce the volatility in customer rates, the Utility has entered into financial swap contracts to effectively fix the price of future purchases and reduce the cash flow variability associated with fluctuating electricity prices under some of those power purchase agreements. These financial swaps are considered derivative instruments.

Electric Transmission Congestion Revenue Rights

The California Independent System Operator ("CAISO") controlled electricity transmission grid used by the Utility to transmit power is subject to transmission constraints. As a result, the Utility is subject to financial risk associated with the cost of transmission congestion. The congestion revenue rights ("CRRs") allow market participants, including load-serving entities, to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. The CAISO releases CRRs through an annual and monthly process, each of which includes an allocation phase (in which load-serving entities are allocated CRRs at no cost based on the customer demand or "load" they serve) and an auction phase (in which CRRs are priced at market and available to all market participants). The Utility participates in the allocation and auction phases of the annual and monthly CRR processes. The CRRs held by the Utility are considered derivative instruments.

Natural Gas Procurement (Electric Fuels Portfolio)

The Utility's electric procurement portfolio is exposed to natural gas price risk primarily through the Utility-owned natural gas generating facilities, tolling agreements, and natural gas-indexed electricity procurement contracts. In order to reduce the volatility in customer rates, the Utility purchases financial instruments such as swaps and options to reduce future cash flow variability associated with fluctuating natural gas prices. These financial instruments are considered derivative instruments.

Natural Gas Procurement (Core Gas Supply Portfolio)

The Utility enters into physical natural gas commodity contracts to fulfill the needs of its residential and smaller commercial customers known as "core" customers. (The Utility does not procure natural gas for industrial and large commercial, or "non-core," customers.) Changes in temperature cause natural gas demand to vary daily, monthly, and seasonally. Consequently, varying volumes of gas may be purchased or sold in the multi-month, monthly, and to a lesser extent, daily spot market to balance such seasonal supply and demand. The Utility purchases financial instruments such as swaps and options as part of its core winter hedging program in order to manage customer exposure to high gas prices during peak winter months. These financial instruments are considered derivative instruments.

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Volume of Derivative Activity

At March 31, 2011, the volumes of PG&E Corporation's and the Utility's outstanding derivative contracts were as follows:

Underlying Product	Instruments	Contract Volume ⁽¹⁾			
		Less Than 1 Year	1 Year but Less Than 3 Years	3 Years but Less Than 5 Years	Greater Than 5 Years ⁽²⁾
Natural Gas ⁽³⁾ (MMBtus ⁽⁴⁾)	Forwards and Swaps	483,012,276	299,055,015	13,642,500	-
	Options	215,050,000	203,350,000	21,000,000	-
Electricity (Megawatt-hours)	Forwards and Swaps	4,738,243	6,526,712	3,297,199	4,674,168
	Options	415,450	24,540	264,348	371,604
	Congestion Revenue Rights	68,367,041	72,547,614	72,642,249	90,055,284

⁽¹⁾ Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each time period.

⁽²⁾ Derivatives in this category expire between 2016 and 2022.

⁽³⁾ Amounts shown are for the combined positions of the electric and core gas portfolios.

⁽⁴⁾ Million British Thermal Units.

Presentation of Derivative Instruments in the Financial Statements

In PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets, derivative instruments are presented on a net basis by counterparty where the right of offset exists under a master netting agreement. The net balances include outstanding cash collateral associated with derivative positions.

At March 31, 2011, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

(in millions)	Gross Derivative		Cash Collateral (2)	Total Derivative
	Balance (1)	Netting (2)		Balances
Commodity Risk (PG&E Corporation and the Utility)				
Current assets –other	59	(47)	128	140
Other noncurrent assets – other	139	(100)	42	81
Current liabilities – other	(371)	47	135	(189)
Noncurrent liabilities – other	(431)	100	48	(283)
Total commodity risk	(604)	-	353	(251)

⁽¹⁾ See Note 8 of the Notes to the Condensed Consolidated Financial Statements for a discussion of the valuation techniques used to calculate the fair value of these instruments.

⁽²⁾ Positions and cash collateral, by counterparty, are netted where the intent and legal right to offset exist in accordance with master netting agreements.

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At December 31, 2010, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

(in millions)	Gross Derivative Balance	Netting (1)	Cash Collateral (1)	Total Derivative Balances
Commodity Risk (PG&E Corporation and the Utility)				
Current assets – other	\$ 56	\$ (45)	\$ 79	\$ 90
Other noncurrent assets – other	77	(62)	96	111
Current liabilities – other	(388)	45	119	(224)
Noncurrent liabilities – other	(486)	62	130	(294)
Total commodity risk	\$ (741)	\$ -	\$ 424	\$ (317)

(1) Positions and cash collateral, by counterparty, are netted where the intent and legal right to offset exist in accordance with master netting agreements.

Gains and losses recorded on PG&E Corporation's and the Utility's derivative instruments were as follows:

(in millions)	Commodity Risk (PG&E Corporation and Utility)	
	Three months ended March 31,	
	2011	2010
Unrealized gain/(loss) - Regulatory assets and liabilities (1)	\$ 137	\$ (289)
Realized loss - Cost of electricity (2)	(136)	(106)
Realized loss - Cost of natural gas (2)	(55)	(39)
Total commodity risk instruments	\$ (54)	\$ (434)
Other Risk Instruments (PG&E Corporation Only)		
Other expense (income), net	\$ -	\$ 1
Total other risk instruments	\$ -	\$ 1

(1) Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory assets or liabilities, rather than being recorded to the Condensed Consolidated Statements of Income. These amounts exclude the impact of cash collateral postings.

(2) These amounts are fully passed through to customers in rates. Accordingly, net income was not impacted by realized amounts on these instruments.

Cash inflows and outflows associated with the settlement of all derivative instruments are included in operating cash flows on PG&E Corporation's and the Utility's Condensed Consolidated Statements of Cash Flows.

The majority of the Utility's commodity-related derivative instruments contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. As of March 31, 2011, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to immediately post additional cash to fully collateralize its net liability derivative positions.

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At March 31, 2011, the additional cash collateral that the Utility would be required to post if its credit risk-related contingency features were triggered was as follows:

(in millions)	
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	(487)
Related derivatives in an asset position	12
Collateral posting in the normal course of business related to these derivatives	16
Net position of derivative contracts/additional collateral posting requirements ⁽¹⁾	<u>(459)</u>

⁽¹⁾ This calculation excludes the impact of closed but unpaid positions, as their settlement is not impacted by any of the Utility's credit risk-related contingencies.

NOTE 8: FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility measure their cash equivalents, trust assets, and price risk management instruments at fair value. Fair value is an exit price, representing the amount that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants. As such, fair value is a market-based measurement that should be determined based on assumptions that market participants would use in pricing an asset or a liability. A three-tier fair value hierarchy is established as a basis for considering such assumptions and for inputs used in the valuation methodologies in measuring fair value:

Level 1 - Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.

Level 2 - Other inputs that are directly or indirectly observable in the marketplace.

Level 3 - Unobservable inputs which are supported by little or no market activities.

The fair value hierarchy requires an entity to maximize the use of observable inputs and minimize the use of unobservable inputs when measuring fair value.

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Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below (money market investments and assets held in rabbi trusts are held by PG&E Corporation and not the Utility):

(in millions)	Fair Value Measurements							
	At March 31, 2011				At December 31, 2010			
	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Assets:								
Money market investments	\$ 187	\$ -	\$ -	\$ 187	\$ 138	\$ -	\$ -	\$ 138
Nuclear decommissioning trusts								
U.S. equity securities ⁽¹⁾	861	8	-	869	1,029	7	-	1,036
Non-U.S. equity securities	360	-	-	360	349	-	-	349
U.S. government and agency securities	647	159	-	806	584	40	-	624
Municipal securities	-	109	-	109	-	119	-	119
Other fixed income securities	-	113	-	113	-	66	-	66
Total nuclear decommissioning trusts ⁽²⁾	1,868	389	-	2,257	1,962	232	-	2,194
Price risk management instruments (Note 7)								
Electric ⁽³⁾	119	11	-	130	130	-	-	130
Gas ⁽⁴⁾	8	-	-	8	3	-	-	3
Total price risk management instruments	127	11	-	138	133	-	-	133
Rabbi trusts								
Fixed income securities	-	24	-	24	-	24	-	24
Life insurance contracts	-	65	-	65	-	65	-	65
Total rabbi trusts	-	89	-	89	-	89	-	89
Long-term disability trust								
U.S. equity securities ⁽¹⁾	4	20	-	24	11	24	-	35
Non-U.S. equity securities	-	8	-	8	-	-	-	-
Corporate debt securities ⁽¹⁾	-	145	-	145	-	150	-	150
Total long-term disability trust	4	173	-	177	11	174	-	185
Total assets	\$ 2,186	\$ 662	\$ -	\$ 2,848	\$ 2,244	\$ 495	\$ -	\$ 2,739
Liabilities:								
Price risk management instruments (Note 7)								
Electric ⁽⁵⁾	\$ -	\$ -	\$ 382	\$ 382	\$ -	\$ 5	\$ 403	\$ 408
Gas ⁽⁶⁾	-	1	6	7	-	1	41	42
Total liabilities	\$ -	\$ 1	\$ 388	\$ 389	\$ -	\$ 6	\$ 444	\$ 450

(1) Level 2 balances include commingled funds, which are comprised primarily of securities traded publicly on exchanges. Price quotes for the assets held by the funds are readily observable and available.

(2) Excludes \$203 million and \$185 million at March 31, 2011 and December 31, 2010, respectively, primarily related to deferred taxes on appreciation of investment value.

(3) Balances include the impact of netting adjustments of \$321 million and \$359 million to Level 1 at March 31, 2011 and December 31, 2010, respectively and \$70 million to Level 2 at March 31, 2011. Includes natural gas for electric portfolio.

(4) Balances include the impact of netting adjustments of \$40 million and \$44 million to Level 1 at March 31, 2011 and December 31, 2010, respectively. Includes natural gas for core customers.

(5) Balances include the impact of netting adjustments of \$66 million to Level 2 at December 31, 2010 and \$(73) million and \$(48) million to Level 3 at March 31, 2011 and December 31, 2010, respectively. Includes natural gas for electric portfolio.

(6) Balances include the impact of netting adjustments of \$(5) million and \$3 million to Level 3 at March 31, 2011 and December 31, 2010, respectively. Includes natural gas for core customers.

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Money Market Investments

PG&E Corporation invests in money market funds that seek to maintain a stable net asset value. These funds invest in high-quality, short-term, diversified money market instruments, such as treasury bills, federal agency securities, certificates of deposit, and commercial paper with a maximum weighted average maturity of 60 days or less. PG&E Corporation's investments in these money market funds are generally valued using unadjusted quotes in an active market for identical assets and are thus classified as Level 1. Money market funds are recorded as cash and cash equivalents in PG&E Corporation's Condensed Consolidated Balance Sheets.

Trust Assets

The assets held by the nuclear decommissioning trusts, the rabbi trusts related to the non-qualified deferred compensation plans, and the long-term disability trust are comprised primarily of equity securities and debt securities. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

Equity investments primarily include investments in common stock and commingled funds comprised of equity securities across multiple industry sectors in the U.S. and other regions of the world. Equity securities are generally valued based on unadjusted prices in active markets for identical transactions and are classified as Level 1.

Debt securities are comprised primarily of fixed income securities that include U.S. government and agency securities, municipal securities, and corporate debt securities. U.S. government and agency securities consist primarily of treasury securities that are classified as Level 1 as the fair value is determined by observable market prices in active markets. A market based valuation approach is generally used to estimate the fair value of debt securities classified as Level 2. Under a market approach, fair values are determined based on evaluated pricing data, such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit rating, coupon rate, and maturity of each security are considered in the valuation, as applicable.

Price Risk Management Instruments

Price risk management instruments include physical and financial derivative contracts, such as forwards, swaps, options, and CRRs that are either exchange-traded or over-the-counter traded. (See Note 7 above.)

Forwards and swaps that are valued using observable market prices for the underlying commodity or an identical instrument and are classified as Level 1 or Level 2. Forwards and swaps that are valued using unobservable data are considered Level 3. These contracts are valued using either estimated basis adjustments from liquid trading points or techniques including extrapolation from observable prices when a contract term extends beyond a period when market data is available.

All energy-related options are classified as Level 3 and are valued using a standard option pricing model with various assumptions, including forward prices for the underlying commodity, time value at a risk free rate, and volatility. For periods in which market data is not available, the Utility extrapolates these assumptions using internal models.

The Utility holds CRRs to hedge financial risk of CAISO-imposed congestion charges in the day-ahead markets. CRRs are valued based on auction prices discounted at the risk free rate. Limited market data is available between auction dates; therefore, CRRs are classified as Level 3.

Transfers between Levels

PG&E Corporation and the Utility recognize any transfers between levels in the fair value hierarchy as of the end of the reporting period. There were no significant transfers between levels for the three months ended March 31, 2011.

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Level 3 Reconciliation

The following table presents reconciliations for assets and liabilities measured and recorded at fair value on a recurring basis for PG&E Corporation and the Utility (money market investments and dividend participation rights are held by PG&E Corporation and not the Utility), using significant unobservable inputs (Level 3):

(in millions)	For the three months ended March 31,					
	2011	Money Market	Dividend Participation	2010	Other Liabilities	Total
	Price Risk Management Instruments		Rights	Price Risk Management Instruments		
Asset (liability) balance as of December 31	\$ (444)	\$ 4	\$ (12)	\$ (217)	\$ (3)	\$ (228)
Realized and unrealized gains (losses):						
Included in earnings	-	-	-	-	-	-
Included in regulatory assets and liabilities or balancing accounts	56	-	-	(119)	2	(117)
Purchases, issuances, sales and settlements	-	(4)	5	-	-	1
Transfers into Level 3	-	-	-	-	-	-
Transfers out of Level 3	-	-	-	-	-	-
Asset (liability) balance as of March 31	\$ (388)	\$ -	\$ (7)	\$ (336)	\$ (1)	\$ (344)

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments:

- The fair values of cash, restricted cash and deposits, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at March 31, 2011 and December 31, 2010.
- The fair values of the Utility's fixed rate senior notes and fixed rate pollution control bond loan agreements, PG&E Corporation's fixed rate senior notes, and the ERBs issued by PERF were based on quoted market prices at March 31, 2011 and December 31, 2010.

The carrying amount and fair value of PG&E Corporation's and the Utility's debt instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

(in millions)	At March 31, 2011		At December 31, 2010	
	Carrying	Fair	Carrying	Fair
	Amount	Value ⁽¹⁾	Amount	Value ⁽¹⁾
Debt (Note 4):				
PG&E Corporation	\$ 349	\$ 382	\$ 349	\$ 383
Utility	9,945	10,524	10,444	11,314
Energy recovery bonds (Note 4)	730	757	827	862

⁽¹⁾ Fair values are determined using readily available quoted market prices.

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Nuclear Decommissioning Trust Investments

The Utility classifies its investments held in the nuclear decommissioning trust as “available-for-sale.” As the day-to-day investing activities of the trusts are managed by external investment managers, the Utility is unable to assert that it has the intent and ability to hold investments to maturity. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refundable or recoverable, respectively, from customers. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of ARO. There is no impact on the Utility’s earnings or accumulated other comprehensive income. (See Note 3 above for further discussion.)

The following table provides a summary of available-for-sale investments held in the Utility’s nuclear decommissioning trusts:

(in millions)	Amortized	Total Unrealized	Total Unrealized	Estimated (1)
	Cost	Gains	Losses	Fair Value
As of March 31, 2011				
Equity securities				
U.S.	\$ 308	\$ 562	\$ (1)	\$ 869
Non-U.S.	182	179	(1)	360
Debt securities				
U.S. government and agency securities	759	50	(3)	806
Municipal securities	108	1	-	109
Other fixed income securities	113	1	(1)	113
Total	\$ 1,470	\$ 793	\$ (6)	\$ 2,257
As of December 31, 2010				
Equity securities				
U.S.	\$ 509	\$ 529	\$ (2)	\$ 1,036
Non-U.S.	180	170	(1)	349
Debt securities				
U.S. government and agency securities	571	55	(2)	624
Municipal securities	119	1	(1)	119
Other fixed income securities	65	1	-	66
Total	\$ 1,444	\$ 756	\$ (6)	\$ 2,194

(1) Excludes \$203 million and \$185 million at March 31, 2011 and December 31, 2010, respectively, primarily related to deferred taxes on appreciation of investment value.

The debt securities mature on the following schedule:

(in millions)	As of March 31, 2011
Less than 1 year	\$ 72
1–5 years	325
5–10 years	286
More than 10 years	345
Total maturities of debt securities	\$ 1,028

The following table provides a summary of activity for the debt and equity securities:

(in millions)	Three Months Ended	
	March 31, 2011	March 31, 2010
Proceeds from sales and maturities of nuclear decommissioning trust investments	\$ 726	\$ 337
Gross realized gains on sales of securities held as available-for-sale	20	15
Gross realized losses on sales of securities held as available-for-sale	(4)	(5)

NOTE 9: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

Various electricity suppliers filed claims in the Utility's Chapter 11 Settlement Agreement seeking payment for energy supplied to the Utility's customers through the wholesale electricity markets operated by the CAISO and the California Power Exchange ("PX") between May 2000 and June 2001. These claims, which the Utility disputes, are being addressed in various FERC and judicial proceedings in which the State of California, the Utility, and other electricity purchasers are seeking refunds from electricity suppliers, including municipal and governmental entities, for overcharges incurred in the CAISO and the PX wholesale electricity markets between May 2000 and June 2001. At March 31, 2011 and December 31, 2010, the Utility held \$384 million and \$512 million in escrow, respectively, including interest earned, for payment of the remaining net disputed claims. These amounts are included within restricted cash on the Condensed Consolidated Balance Sheets.

While the FERC and judicial proceedings have been pending, the Utility entered into a number of settlements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. These settlement agreements provide that the amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. The proceeds from these settlements, after deductions for contingencies based on the outcome of the various refund offset and interest issues being considered by the FERC, will continue to be refunded to customers in rates. Additional settlement discussions with other electricity suppliers are ongoing. Any net refunds, claim offsets, or other credits that the Utility receives from energy suppliers through resolution of the remaining disputed claims, either through settlement or the conclusion of the various FERC and judicial proceedings, will also be refunded to customers.

The following table presents the changes in the remaining net disputed claims liability:

(in millions)	
Balance at December 31, 2010	\$ 934
Interest accrued	7
Less: supplier settlements	(86)
Balance at March 31, 2011	\$ 855

At March 31, 2011, the Utility's net disputed claims liability was \$855 million, consisting of \$691 million of remaining disputed claims (classified on the Condensed Consolidated Balance Sheets within accounts payable – disputed claims and customer refunds) and interest accrued at the FERC-ordered rate of \$658 million (classified on the Condensed Consolidated Balance Sheets within interest payable) partially offset by accounts receivable from the CAISO and the PX of \$494 million (classified on the Condensed Consolidated Balance Sheets within accounts receivable – other).

Interest accrues on the net liability for disputed claims at the FERC-ordered rate, which is higher than the rate earned by the Utility on the escrow balance. Although the Utility has been collecting the difference between the accrued interest and the earned interest from customers, this amount is not held in escrow. If the amount of interest accrued at the FERC-ordered rate is greater than the amount of interest ultimately determined to be owed with respect to disputed claims, the Utility would refund to customers any excess net interest collected from customers. The amount of any interest that the Utility may be required to pay will depend on the final amounts to be paid by the Utility with respect to the disputed claims and when such interest is paid.

PG&E Corporation and the Utility are unable to predict when the FERC or judicial proceedings that are still pending will be resolved, and the amount of any potential refunds that the Utility may receive or the amount of disputed claims, including interest that the Utility will be required to pay.

NOTE 10: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have substantial financial commitments in connection with agreements entered into to support the Utility's operating activities. PG&E Corporation and the Utility also have significant contingencies arising from their operations, including contingencies related to guarantees, regulatory proceedings, nuclear operations, environmental compliance and remediation, tax matters, and legal matters.

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Commitments

Utility

Third-Party Power Purchase Agreements

As part of the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity. The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either gas or electricity at the date of purchase.

At March 31, 2011, the undiscounted future expected power purchase agreement payments were as follows:

(in millions)	
2011	\$ 2,076
2012	2,553
2013	3,004
2014	3,276
2015	3,478
Thereafter	54,390
Total	\$ 68,777

Costs incurred by the Utility under power purchase agreements amounted to \$587 million and \$201 million for the three months ended March 31, 2011 and 2010, respectively.

Some of the power purchase agreements that the Utility entered into are treated as capital leases. The following table shows the future fixed capacity payments due under the contracts that are treated as capital leases. The fixed capacity payments are discounted to their present value in the table below using the Utility's incremental borrowing rate at the inception of the leases. The amount of this discount is shown in the table below as the amount representing interest.

(in millions)	
2011	\$ 43
2012	50
2013	50
2014	42
2015	38
Thereafter	124
Total fixed capacity payments	347
Less: amount representing interest	(68)
Present value of fixed capacity payments	\$279

Minimum lease payments associated with the lease obligation are included in cost of electricity on PG&E Corporation's and the Utility's Condensed Consolidated Statements of Income. The timing of the recognition of the lease expense conforms to the ratemaking treatment for the Utility's recovery of the cost of electricity. The contracts that are treated as capital leases expire between April 2014 and September 2021.

At March 31, 2011 and December 31, 2010, current liabilities – other included \$34 million and \$34 million, respectively, and noncurrent liabilities – other included \$245 million and \$248 million, respectively. The corresponding assets at March 31, 2011 and December 31, 2010 of \$279 million and \$282 million including accumulated amortization of \$129 million and \$126 million, respectively are included in property, plant, and equipment on PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets.

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Natural Gas Supply, Transportation, and Storage Commitments

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities. The contract lengths and quantities of the Utility's portfolio of natural gas procurement contracts can fluctuate based on market conditions. The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. In addition, the Utility has contracted for gas storage services in northern California in order to better meet core customers' winter peak loads. At March 31, 2011, the Utility's undiscounted obligations for natural gas purchases, natural gas transportation services, and natural gas storage were as follows:

(in millions)	
2011	\$ 659
2012	514
2013	258
2014	209
2015	195
Thereafter	1,141
Total ⁽¹⁾	\$ 2,976

⁽¹⁾ Amounts above include firm transportation contracts for the Ruby Pipeline (a 1.5 billion cubic feet per day ("bcf/d") pipeline which is currently under construction and expected to become operational in the summer of 2011. The Utility has contracted for a capacity of approximately 0.4 bcf/d).

Costs incurred for natural gas purchases, natural gas transportation services, and natural gas storage amounted to \$433 million and \$553 million for the three months ended March 31, 2011 and March 31, 2010, respectively.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from one to 14 years and are intended to ensure long-term fuel supply. The contracts for uranium and for conversion and enrichment services provide for 100% coverage of reactor requirements through 2016, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2017. The Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices. New agreements are primarily based on forward market pricing.

At March 31, 2011, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2011	\$ 65
2012	83
2013	125
2014	143
2015	200
Thereafter	1,065
Total	\$1,681

Payments for nuclear fuel amounted to \$29 million and \$53 million for the three months ended March 31, 2011 and March 31, 2010, respectively.

Contingencies

PG&E Corporation

PG&E Corporation retains a guarantee related to certain obligations of its former subsidiary, National Energy and Gas Transmission, Inc. ("NEGT"), that were issued to the purchaser of an NEGТ subsidiary company in 2000. PG&E Corporation's primary remaining exposure relates to any potential environmental obligations that were known to NEGТ at the time of the sale but not disclosed to the purchaser, and is limited to \$150 million. PG&E Corporation has not received any claims nor does it consider it probable that any claims will be made under the guarantee. PG&E Corporation believes that its potential exposure under this guarantee would not have a material impact on its financial condition or results of operations.

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Utility

Energy Efficiency Programs and Incentive Ratemaking

On November 15, 2010, a proposed decision was issued that if, adopted by the CPUC, would modify the incentive mechanism that would apply to the 2010 through 2012 program cycle. Among other changes, the proposed modification would limit the total amount of the incentive award or penalty that could be awarded to, or imposed on, all the investor-owned utilities to \$189 million. If the proposed decision is adopted, the Utility's opportunity to earn incentive revenues would be limited compared to the mechanism that was in place for the 2006-2008 program cycle.

Spent Nuclear Fuel Storage Proceedings

As part of the Nuclear Waste Policy Act of 1982, Congress authorized the U.S. Department of Energy ("DOE") and electric utilities with commercial nuclear power plants to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste no later than January 31, 1998, in exchange for fees paid by the utilities. In 1983, the DOE entered into a contract with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and its retired nuclear facility at Humboldt Bay ("Humboldt Bay Unit 3").

Because the DOE failed to develop a permanent storage site, the Utility obtained a permit from the Nuclear Regulatory Commission ("NRC") to build an on-site dry cask storage facility to store spent fuel at Diablo Canyon through at least 2024. The construction of the dry cask storage facility is complete. During 2009 and 2010, the Utility moved all the spent nuclear fuel that was scheduled to be moved into dry cask storage. An appeal of the NRC's issuance of the permit, which claimed that the NRC failed to adequately consider environmental impacts of a potential terrorist attack at Diablo Canyon, was denied by the U.S. Court of Appeals for the Ninth Circuit on February 15, 2011.

As a result of the DOE's failure to build a repository for nuclear waste, the Utility and other nuclear power plant owners sued the DOE to recover costs that they incurred to build on-site spent nuclear fuel storage facilities. The Utility sought to recover \$92 million of costs that it incurred through 2004. After several years of litigation, on March 30, 2010, the U.S. Court of Federal Claims awarded the Utility \$89 million. The DOE filed an appeal of this decision on May 28, 2010. The appeal was argued in the

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Federal Circuit Court of Appeals on March 10, 2011. Additionally, on August 3, 2010, the Utility filed two complaints against the DOE in the U.S. Court of Federal Claims seeking to recover all costs incurred since 2005 to build on-site storage facilities. The Utility estimates that it has incurred costs of at least \$205 million since 2005. Amounts recovered from the DOE will be credited to customers.

Nuclear Insurance

The Utility has several types of nuclear insurance for the two nuclear operating units at Diablo Canyon and for its retired nuclear generation facility at Humboldt Bay Unit 3. The Utility has insurance coverage for property damages and business interruption losses as a member of Nuclear Electric Insurance Limited (“NEIL”). NEIL is a mutual insurer owned by utilities with nuclear facilities. NEIL provides property damage and business interruption coverage of up to \$3.2 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 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 terrorism cause damages covered under any of the nuclear insurance policies issued by NEIL to any NEIL member, the maximum recovery under all those nuclear insurance policies may not exceed NEIL’s policy limit of \$3.2 billion within a 12-month period plus any additional amounts recovered by NEIL for these losses from reinsurance. Certain acts of terrorism may be “certified” by the Secretary of the Treasury. For damages caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of \$3.2 billion for each insured loss caused by these certified acts of terrorism. The \$3.2 billion amount would not be shared as is described above for damages caused by acts of terrorism that have not been certified.

Under the Price-Anderson Act, public liability claims that arise from nuclear incidents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to \$12.6 billion. As required by the Price-Anderson Act, the Utility purchased the maximum available public liability insurance of \$375 million for Diablo Canyon. The balance of the \$12.6 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to \$235 million per nuclear incident under this program, with payments in each year limited to a maximum of \$35 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before October 29, 2013.

The Price-Anderson Act does not apply to public liability claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator’s facility. Such claims are covered by nuclear liability policies purchased by the enricher and the fuel fabricator as well as by separate supplier’s and transporter’s (“S&T”) insurance policies. The Utility has a S&T policy that provides coverage for claims arising from some of these incidents up to a maximum of \$375 million per incident. The Utility could incur losses that are either not covered by insurance or exceed the amount of insurance available.

In addition, the Utility has \$53 million of liability insurance for Humboldt Bay Unit 3 and has a \$500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the \$53 million of liability insurance.

Legal Matters

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, PG&E Corporation and the Utility are named as parties in a number of claims and lawsuits. In addition, the Utility can incur penalties for failure to comply with federal, state, or local laws and regulations.

PG&E Corporation and the Utility record 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. PG&E Corporation and the Utility evaluate the range of reasonably estimated costs and record a liability based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. These accruals, and the estimates of any additional reasonably possible losses, are reviewed quarterly and are adjusted to reflect the impacts of negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. In assessing such contingencies, PG&E Corporation’s and the Utility’s policy is to exclude anticipated legal costs.

The accrued liability associated with claims and litigation, regulatory proceedings, and other legal matters (other than third-party liability claims related to the San Bruno accident as discussed below) totaled \$87 million at March 31, 2011 and \$55 million at December 31, 2010 and is included in PG&E

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Corporation's and the Utility's current liabilities – other in the Condensed Consolidated Balance Sheets. Except as discussed below, PG&E Corporation and the Utility do not believe that losses associated with legal matters would have a material adverse impact on their financial condition, results of operations, or cash flows after consideration of the accrued liability at March 31, 2011.

Explosion and Fires in San Bruno, California

On September 9, 2010, an underground 30-inch natural gas transmission pipeline (line 132) owned and operated by the Utility, ruptured in a residential area located in the City of San Bruno, California ("San Bruno accident"). The ensuing explosion and fire resulted in the deaths of eight people, injuries to numerous individuals, and extensive property damage. The NTSB has issued several public statements regarding its investigation of the San Bruno accident but has not yet determined the cause of the pipeline rupture. During the quarter ended March 31, 2011, the CPUC initiated an investigation pertaining to safety recordkeeping for the Utility's gas transmission pipeline that ruptured in San Bruno, as well as for its entire gas transmission system, which is discussed below.

In addition to these investigations, as of March 31, 2011, 74 tort lawsuits on behalf of approximately 224 plaintiffs, including two class action lawsuits, have been filed against PG&E Corporation and the Utility. Five of the lawsuits on behalf of 11 plaintiffs were filed in the San Francisco County Superior Court; the rest were filed in San Mateo County Superior Court. These tort lawsuits seek compensation for personal injury and property damage and seek other relief. The class action lawsuits allege causes of action for strict liability, negligence, public nuisance, private nuisance, and declaratory relief. Several other residents of San Bruno also have submitted damage claims to the Utility. These lawsuits have been coordinated and assigned to one judge in the San Mateo County Superior Court.

The Utility recorded a provision of \$220 million in 2010 for estimated third-party claims related to the San Bruno accident, including personal injury and property damage claims, damage to infrastructure, and other damage claims. The provision also included estimated liabilities to reimburse the City of San Bruno for costs it incurred related to the fires caused by the pipeline rupture. As of March 31, 2011 and December 31, 2010, \$198 million and \$214 million, respectively, was accrued as a liability in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets. The change in the liability from December 31, 2010 was due to payments made to third parties.

The Utility currently estimates that it may incur as much as \$400 million for third-party claims. As more information becomes known, including information resulting from the NTSB and CPUC investigations, management's estimates and assumptions regarding the amount of third-party liability incurred in connection with the San Bruno accident may change. It is possible that a change in estimate could have a material adverse impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

The Utility maintains liability insurance for damages in the approximate amount of \$992 million in excess of a \$10 million deductible. Although PG&E Corporation and the Utility currently consider it likely that a significant portion of the costs the Utility incurs for third-party claims relating to the San Bruno accident will ultimately be covered through this insurance, no amount for insurance recoveries has been recorded as of March 31, 2011. PG&E Corporation and the Utility are unable to predict the amount and timing of insurance recoveries.

CPUC Investigations

On February 24, 2011, the CPUC issued an order instituting a formal investigation ("OII") pertaining to safety recordkeeping for the Utility's gas transmission pipeline that ruptured in San Bruno on September 9, 2010, as well as for its entire gas transmission system. The CPUC stated that in deciding to issue the OII, it had relied on the NTSB's public preliminary reports issued in connection with its investigation of the San Bruno accident, the NTSB's January 3, 2011 urgent safety recommendations regarding the importance of accurate pipeline records in calculating maximum safe operating pressures, and other NTSB statements. After the NTSB has completed its investigation and issued a final report, the CPUC also will consider other possible violations of law, besides recordkeeping, associated with the Utility's transmission lines and with Line 132 in particular.

If the CPUC determines that the Utility violated safety law standards with respect to its gas system recordkeeping, the CPUC will schedule a later phase or phases to determine whether penalties are warranted, and if so the amount of such penalties. It is anticipated that the administrative law judge will set the procedural schedule after a second pre-hearing conference is held during the week of May 9, 2011.

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The CPUC also is investigating a natural gas explosion and fire that occurred on December 24, 2008 in a house located in Rancho Cordova, California (“Rancho Cordova accident”). On February 17, 2011, the Utility submitted its report to the CPUC to provide extensive information, from as far back as January 1, 2000, about the Utility’s natural gas operating and maintenance practices and procedures. The Utility’s report agrees with the NTSB’s conclusions about the probable cause of the accident and explains what process improvements the Utility has made to prevent a similar accident in the future. The CPUC has scheduled an evidentiary hearing in mid-July.

If the CPUC determines that the Utility violated applicable laws in connection with the San Bruno or Rancho Cordova accidents, the CPUC could impose penalties of up to \$20,000 per day, per violation which, in the aggregate, could have a material adverse impact on PG&E Corporation’s and the Utility’s financial condition, results of operations, or cash flows. Estimated liabilities associated with the Rancho Cordova investigation are included in the accrual for legal matters discussed above. In addition, law enforcement authorities could begin proceedings that could result in the imposition of civil or criminal fines or penalties on the Utility. PG&E Corporation and the Utility are unable to predict the ultimate outcome of the investigations discussed above or whether additional investigations or proceedings will be instituted.

Environmental Matters

The Utility has been, and may be required to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant (“MGP”) sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site.

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment. The Utility records an environmental remediation liability when site assessments indicate that remediation is probable and it can reasonably estimate the loss within a range of possible amounts.

The Utility records an environmental remediation liability based on the lower end of the range of estimated costs, unless an amount within the range is a better estimate than any other amount. Amounts recorded are not discounted to their present value.

The Utility had an undiscounted and gross environmental remediation liability of \$627 million at March 31, 2011 and \$612 million at December 31, 2010. The following table presents the changes in the environmental remediation liability from December 31, 2010:

(in millions)	
Balance at December 31, 2010	\$ 612
Additional remediation costs accrued:	
Transfer to regulatory account for recovery	33
Amounts not recoverable from customers	9
Less: Payments	(27)
Balance at March 31, 2011	<u>\$ 627</u>

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The \$627 million accrued at March 31, 2011 consists of the following:

- \$45 million for remediation at the Utility's natural gas compressor site located near Hinkley, California;
- \$180 million for remediation at the Utility's natural gas compressor site located on the California border, near Topock, Arizona;
- \$83 million related to remediation at divested generation facilities;
- \$117 million related to remediation costs for the Utility's generation and other facilities and for third-party disposal sites;
- \$142 million related to investigation and/or remediation costs at former MGP sites owned by the Utility or third parties (including those sites that are the subject of remediation orders by environmental agencies or claims by the current owners of the former MGP sites); and
- \$60 million related to remediation costs for fossil decommissioning sites.

Of the \$627 million environmental remediation liability, the Utility expects to recover \$327 million through the CPUC-approved ratemaking mechanism that authorizes the Utility to recover 90% of hazardous waste remediation costs without a reasonableness review (excluding any remediation associated with the Hinkley natural gas compressor site) and \$135 million through the ratemaking mechanism that authorizes the Utility to recover 100% of remediation costs for decommissioning fossil-fueled sites and certain of the Utility's transmission stations (excluding any remediation associated with divested generation facilities). 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.

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized. The Utility's undiscounted future costs could increase to as much as \$1.2 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Recovery of these amounts would be subject to CPUC approval.

Tax Matters

In tax year 2008, PG&E Corporation began participating in the Compliance Assurance Process ("CAP"), a real-time Internal Revenue Service ("IRS") audit intended to expedite resolution of tax matters. The CAP audit culminates with a letter from the IRS indicating their acceptance of the return. The IRS partially accepted the 2008 return, withholding two issues for further review. The most significant of these relates to a tax accounting method change filed by PG&E Corporation to accelerate the amount of deductible repairs. While the IRS approved PG&E Corporation's request for a change in method, the IRS will audit the methodology to determine the proper deduction. This audit has not progressed significantly because the IRS is working with the utility industry to resolve this matter in a consistent manner for all utilities before auditing individual companies. In December 2010, the IRS accepted PG&E Corporation's 2009 tax return. PG&E Corporation is currently under audit for the 2010 CAP year.

PG&E Corporation and the Utility expect the IRS to release new guidance clarifying the treatment of deductible repairs within the next 12 months. This guidance may result in a change in unrecognized tax benefits. PG&E Corporation and the Utility are unable to determine the potential impact of this change to the unrecognized tax benefits at this time.

The California Franchise Tax Board ("FTB") is auditing PG&E Corporation's 2004 and 2005 combined California income tax returns, as well as the 1997-2007 amended income tax returns reflecting IRS settlements for these years and claim filings that apply only to California. PG&E Corporation expects the FTB to complete the 1997 to 2004 audit by the end of 2011. It is uncertain when the FTB will complete the remaining audits.

PG&E Corporation believes that the final resolution of the federal and California audits will not have a material adverse impact on its financial condition or results of operations. PG&E Corporation is neither under audit nor subject to any material risk in any other jurisdiction.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary purpose is to hold interests in energy-based businesses. PG&E Corporation conducts its business principally through Pacific Gas and Electric Company ("Utility"), a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. 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.

The Utility served 5.2 million electricity distribution customers and 4.3 million natural gas distribution customers at March 31, 2011. The Utility had \$45.9 billion in assets at March 31, 2011 and generated revenues of \$3.6 billion in the three months ended March 31, 2011.

The Utility is regulated primarily by the California Public Utilities Commission ("CPUC") and the Federal Energy Regulatory Commission ("FERC"). In addition, the Nuclear Regulatory Commission ("NRC") oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities, including the Diablo Canyon power plant ("Diablo Canyon"). The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electric and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and over the rates and terms and conditions of service governing the Utility on its interstate natural gas transportation contracts. Before setting rates, the CPUC and the FERC authorize the annual amount of revenue ("revenue requirements") that the Utility is authorized to collect from its customers to recover its reasonable operating and capital costs of providing utility services. The authorized revenue requirements also provide the Utility an opportunity to earn a return on "rate base" (i.e., the Utility's net investment in facilities, equipment, and other property used or useful in providing utility service to its customers.) The CPUC requires the Utility to maintain a certain capital structure (i.e., the relative weightings of common equity, preferred equity, and debt) when financing its rate base and authorizes the Utility to earn a specific rate of return on each capital component.

This is a combined quarterly report of PG&E Corporation and the Utility and should be read in conjunction with each company's separate Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in this quarterly report. In addition, this quarterly report should be read in conjunction with PG&E Corporation's and the Utility's combined Annual Report on Form 10-K for the year ended December 31, 2010 which incorporates by reference each company's audited Consolidated Financial Statements, the Notes to the Consolidated Financial Statements, and other information ("2010 Annual Report").

Key Factors Affecting Results of Operations and Financial Condition

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, recover its authorized costs timely, and earn its authorized rate of return. A number of factors have had, or are expected to have, a significant impact on PG&E Corporation's and the Utility's results of operations and financial condition, including:

- *The Outcome of Matters Related to the Utility's Natural Gas Pipeline System.* The National Transportation Safety Board ("NTSB") is continuing its investigation of the rupture of a Utility-owned natural gas pipeline on September 9, 2010 in San Bruno, California (the "San Bruno accident"). The NTSB has issued several public statements regarding its investigation of the San Bruno accident but has not yet determined the cause of the pipeline rupture. The CPUC is also investigating a natural gas explosion and fire that occurred on December 24, 2008 in a house located in Rancho Cordova, California (the "Rancho Cordova accident"). If the CPUC finds that the Utility violated applicable law in connection with these accidents, the CPUC may impose substantial penalties on the Utility. (See "Natural Gas Pipeline Matters" below). During the quarter ended March 31, 2011, the CPUC opened a rule-making proceeding and initiated a formal investigation of the Utility's gas transmission pipeline recordkeeping. The Utility currently estimates that in 2011 it will incur incremental costs associated with its natural gas transmission business, including costs to comply with CPUC orders and NTSB recommendations, ranging from \$350 million to \$550 million. (See "Operating and Maintenance" and "Natural Gas Pipeline Matters" below.) These cost estimates could change depending on a number of factors, including the outcome of regulatory proceedings and pending investigations, as well as future rulemaking, ratemaking, or other investigatory proceedings that may be commenced at the CPUC. If state or federal legislation is enacted to address natural gas transmission operations and maintenance, the Utility may incur additional costs to comply with such new statutory requirements. It is uncertain how much of the costs the Utility incurs to comply with orders, recommendations, new CPUC regulations, or new legislation, will be recoverable through rates. In addition, various civil lawsuits have been filed by residents of San Bruno in California state courts against PG&E Corporation and the Utility related to

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the San Bruno accident. The Utility currently estimates that it may incur as much as \$400 million for third-party claims, including the \$220 million provision recorded for the year ended December 31, 2010. (See Note 10 to the Notes of the Condensed Consolidated Financial Statements.) The total amount of third-party liability claims will depend on the final determination of the causes for the pipeline rupture and responsibility for the personal injuries and property damages, and the number and nature of third-party claims. Although PG&E Corporation and the Utility currently consider it likely that a significant portion of the costs the Utility incurs for third-party claims will ultimately be covered by its liability insurance, no amounts for insurance recoveries have been recorded as of March 31, 2011. The resolutions of the various regulatory matters and the outcome of the pending investigations and third-party claims may have a material adverse impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

- *The Timing and Outcome of Ratemaking and Other Regulatory Proceedings*. The majority of the Utility's base revenue requirements for 2011 and several years thereafter are determined in various rate cases at the CPUC and the FERC. On April 14, 2011, the CPUC issued a decision in the Utility's 2011 Gas Transmission and Storage rate case ("GT&S") authorizing the Utility to collect increased revenue requirements from January 1, 2011. In the Utility's 2011 General Rate Case ("GRC") the CPUC will authorize a change in revenue requirements beginning on January 1, 2011, but the CPUC has not yet issued a decision. These and other regulatory proceedings are discussed under "Regulatory Matters" below. From time to time, the Utility also requests that the CPUC authorize additional base revenue requirements for specific capital expenditure projects, such as new power plants. The outcome of these proceedings can be affected by many factors, including general economic conditions, the level of customer rates, and political and regulatory policies. (See "Risk Factors" in the 2010 Annual Report.)
- *The Ability of the Utility to Control Operating Costs and Capital Expenditures*. The Utility's revenue requirements are generally set by the CPUC and the FERC at a level to allow the Utility the opportunity to recover its forecasted operating expenses, to recover depreciation, tax, and interest expenses associated with forecasted capital expenditures, and to earn a return on equity ("ROE"). Actual costs may differ from forecasts, or the Utility may incur significant unanticipated costs, such as costs related to storms, outages, catastrophic events, or costs incurred to comply with regulatory orders or legislation. For example, during the three months ended March 31, 2011, the Utility incurred comparatively higher expenses to respond to winter storms, as shown in the table below. As noted above, the Utility expects to incur material costs during 2011 to comply with CPUC orders and NTSB recommendations that have been issued in connection with the investigations of the San Bruno accident. (See "Operating and Maintenance" and "Natural Gas Pipeline Matters" below.) Differences in the amount or timing of forecasted or authorized and actual costs can affect the Utility's ability to earn its authorized rate of return and the amount of PG&E Corporation's income available for common shareholders. To the extent the Utility is unable to conclude that costs are probable of recovery through rates, the Utility will incur a charge to income.
- *Authorized Capital Structure, Rate of Return, and Financing*. The Utility's CPUC-authorized capital structure for its electric and natural gas distribution and electric generation rate base consisting of 52% common equity and 48% debt and preferred stock is scheduled to remain in effect through 2012. The Utility's CPUC-authorized ROE of 11.35% is scheduled to remain in effect through 2012 but is subject to change based on an annual adjustment mechanism as described in the 2010 Annual Report. The timing and amount of the Utility's future debt financing will depend primarily on the timing and amount of its capital expenditures. PG&E Corporation contributes equity to the Utility as needed by the Utility to maintain its CPUC-authorized capital structure. As the Utility incurs costs to perform pipeline safety-related work as described above, the amount of equity needed by the Utility to maintain its capital structure is anticipated to increase. PG&E Corporation anticipates issuing equity in the future to meet the Utility's additional equity needs. (See "Liquidity and Financial Resources" below.)

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Summary of Changes in Earnings per Common Share and Income Available for Common Shareholders for the Three Months Ended March 31, 2011

PG&E Corporation's income available for common shareholders decreased by \$59 million, or 23%, from \$258 million for the three months ended March 31, 2010 to \$199 million for the three months ended March 31, 2011. The following table is a summary reconciliation of the key changes in income available for common shareholders and earnings per common share for the three months ended March 31, 2011:

(in millions)	Earnings Per	
	Earnings	Common Share (Diluted)
Income Available for Common Shareholders – March 31, 2010	\$ 258	\$ 0.67
Natural gas pipeline matters ⁽¹⁾	(31)	(0.08)
Delay in rate case decisions ⁽²⁾	(27)	(0.07)
Storm and outage expenses ⁽³⁾	(18)	(0.05)
Statewide ballot initiative ⁽⁴⁾	25	0.07
Federal healthcare law ⁽⁵⁾	20	0.05
Other ⁽⁶⁾	(28)	(0.06)
Increase in shares outstanding ⁽⁷⁾	-	(0.03)
Income Available for Common Shareholders – March 31, 2011	\$ 199	\$ 0.50

⁽¹⁾ During the three months ended March 31, 2011, the Utility incurred costs of \$31 million, after-tax, to comply with CPUC orders and NTSB recommendations that have been issued in connection with investigations related to the San Bruno accident. These costs are primarily associated with an extensive review of the Utility's pipeline records, as well as other activities associated with the accident and pending investigations.

⁽²⁾ During the three months ended March 31, 2011, the Utility incurred an unfavorable variance of \$27 million, after-tax, representing expenses that would have been offset by increased revenues if the CPUC had issued final decisions in the Utility's Gas Transmission and Storage Case and 2011 General Rate Case before March 31, 2011.

⁽³⁾ During the three months ended March 31, 2011, the Utility incurred higher expenses of \$18 million, after-tax, due to more severe winter storms as compared to the same period in 2010.

⁽⁴⁾ During the three month period ended March 31, 2010, PG&E Corporation contributed \$25 million to support Proposition 16 - The Taxpayers Right to Vote Act.

⁽⁵⁾ During the three months ended March 31, 2010, the Utility recorded a charge of \$20 million triggered by the elimination of the tax deductibility of Medicare Part D federal subsidies.

⁽⁶⁾ During the three months ended March 31, 2011, the Utility incurred higher legal expenses, environmental remediation expenses, and other operating and maintenance expenses, partially offset by an increase in rate base earnings for electric transmission and separately funded projects, as compared to the same period in 2010.

⁽⁷⁾ Represents the impact of a higher number of shares outstanding at March 31, 2011, compared to the number of shares outstanding at March 31, 2010; this has no dollar impact on earnings.

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated capital expenditures; estimated environmental remediation, tax, and other liabilities; estimates and assumptions used in PG&E Corporation's and the Utility's critical accounting policies; the anticipated outcome of various regulatory, governmental, and legal proceedings; estimated losses and insurance recoveries associated with the San Bruno accident; estimated future cash flows; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "plan," "project," "believe," "estimate," "target," "predict," "anticipate," "aim," "may," "might," "should," "would," "could," "goal," "potential," and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the Utility's ability to efficiently manage capital expenditures and its operating and maintenance expenses within authorized levels and timely recover its costs through rates;
- the outcome of pending and future regulatory, legislative, or other proceedings or investigations, including the investigations by the NTSB and CPUC into the cause of the San Bruno accident and the safety of the Utility's natural gas transmission pipelines in its northern and central California service territory; the CPUC investigation of the Rancho Cordova accident; whether the Utility incurs civil or criminal penalties as a result of these proceedings; whether the Utility is required to incur additional costs for third-

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party liability claims or to comply with regulatory or legislative mandates that the Utility is unable to recover through rates or insurance; and whether the Utility incurs third-party liabilities or other costs in connection with service disruptions that may occur as the Utility complies with regulatory orders to decrease pressure in its natural gas transmission system;

- reputational harm that PG&E Corporation and the Utility may suffer depending on the outcome of the various investigations, including those by the NTSB and the CPUC, the outcome of civil litigation, and the extent to which civil or criminal proceedings may be pursued by regulatory or governmental agencies;
- the adequacy and price of electricity and natural gas supplies the extent to which the Utility can manage and respond to the volatility of electricity and natural gas prices, and the ability of the Utility and its counterparties to post or return collateral;
- explosions, fires, accidents, mechanical breakdowns, the disruption of information technology and systems, human errors, and similar events that may occur while operating and maintaining an electric and natural gas system in a large service territory with varying geographic conditions that can cause unplanned outages, reduce generating output, damage the Utility's assets or operations, subject the Utility to third-party claims for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory fines or penalties on the Utility;
- the impact of storms, earthquakes, floods, drought, wildfires, disease, and similar natural disasters, or acts of terrorism or vandalism, that affect customer demand or that damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies;
- the potential impacts of climate change on the Utility's electricity and natural gas businesses;
- changes in customer demand for electricity ("load") and natural gas resulting from unanticipated population growth or decline, general economic and financial market conditions, changes in technology that include the development of alternative technologies that enable customers to increase their reliance on self-generation, or other reasons;
- the occurrence of unplanned outages at the Utility's two nuclear generating units at Diablo Canyon, the availability of nuclear fuel, the outcome of seismic studies the Utility is conducting in the area near Diablo Canyon that could affect the Utility's ability to operate Diablo Canyon or renew the operating licenses for Diablo Canyon, and the ability of the Utility to procure replacement electricity if nuclear generation from Diablo Canyon were unavailable;
- the impact that the recent earthquake and tsunami in Japan may have on the Utility's ability to continue its nuclear operations at Diablo Canyon or to renew the operating licenses for Diablo Canyon as a result of new legislation that may be adopted, or new orders or regulations that may be issued by the NRC or environmental agencies with respect to the operations, decommissioning, storage of spent nuclear fuel, security, safety, cooling water intake, or other matters associated with the operations at Diablo Canyon;
- whether the Utility earns incentive revenues or incurs obligations under incentive ratemaking mechanisms, such as the CPUC's incentive ratemaking mechanism relating to energy savings achieved through implementation of the utilities' customer energy efficiency programs;
- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies;
- whether the Utility can successfully complete its program to install advanced meters for its electric and natural gas customers, allay customer concerns about the new metering technology, and integrate the new meters with its customer billing and other systems while also implementing the system design changes necessary to accommodate retail electric rates based on dynamic pricing (i.e., electric rates that can vary with the customer's time of use and are more closely aligned with wholesale electricity prices);
- how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company and the extent to which the interpretation or enforcement of these conditions has a material impact on PG&E Corporation;
- the extent to which PG&E Corporation or the Utility incurs costs in connection with third-party claims or litigation, that are not recoverable through insurance, rates, or from other third parties;

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- the ability of PG&E Corporation, the Utility, and counterparties to access capital markets and other sources of credit in a timely manner on acceptable terms;
- the impact of environmental laws and regulations addressing the reduction of carbon dioxide and other greenhouse gases (“GHG”), water, the remediation of hazardous waste, and other matters, and whether the Utility is able to recover the costs of compliance with such laws, including the cost of emission allowances and offsets that the Utility may incur under federal or state cap and trade regulations;
- the loss of customers due to various forms of bypass and competition, including municipalization of the Utility’s electric distribution facilities, increasing levels of “direct access” by which consumers procure electricity from alternative energy providers, and implementation of “community choice aggregation,” which permits cities and counties to purchase and sell electricity for their local residents and businesses; and
- the outcome of federal or state tax audits and the impact of changes in federal or state tax laws, policies, or regulations, such as The Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010 (the “Tax Relief Act”).

For more information about the 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, see the section entitled “Risk Factors” in the 2010 Annual Report and Item 1.A. Risk Factors, below. PG&E Corporation and the Utility do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

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RESULTS OF OPERATIONS

The table below details certain items from the accompanying Condensed Consolidated Statements of Income for the three months ended March 31, 2011 and 2010:

(in millions)	Three Months ended March 31,	
	2011	2010
Utility		
Electric operating revenues	\$ 2,616	\$ 2,510
Natural gas operating revenues	980	965
Total operating revenues	3,596	3,475
Cost of electricity	888	920
Cost of natural gas	508	495
Operating and maintenance	1,226	990
Depreciation, amortization, and decommissioning	490	451
Total operating expenses	3,112	2,856
Operating income	484	619
Interest income	2	2
Interest expense	(171)	(156)
Other income (expense), net	17	(6)
Income before income taxes	332	459
Income tax provision	131	195
Net Income	201	264
Preferred stock dividend requirement	3	3
Income available for common stock	\$ 198	\$ 261
PG&E Corporation, Eliminations, and Other ⁽¹⁾		
Operating revenues	\$ 1	\$ -
Operating expenses	1	1
Operating loss	-	(1)
Interest income	-	-
Interest expense	(6)	(12)
Other expense, net	-	-
Loss before income taxes	(6)	(13)
Income tax benefit	(7)	(10)
Net (loss) gain	\$ 1	\$ (3)
Consolidated Total		
Operating revenues	\$ 3,597	\$ 3,475
Operating expenses	3,113	2,857
Operating income	484	618
Interest income	2	2
Interest expense	(177)	(168)
Other income (expense), net	17	(6)
Income before income taxes	326	446
Income tax provision	124	185
Net Income	202	261
Preferred stock dividend requirement of subsidiary	3	3
Income available for common shareholders	\$ 199	\$ 258

⁽¹⁾ PG&E Corporation eliminates all intercompany transactions in consolidation.

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Utility

The following presents the Utility's operating results for the three months ended March 31, 2011 and 2010. These operating results do not reflect the increase in revenues that is expected to occur upon authorization of the 2011 GRC by the CPUC. Revenues will be adjusted retroactively once a final decision is approved for the 2011 GRC. Revenues will also be retroactively adjusted during the second quarter of 2011 as a result of the CPUC's final decision in the 2011 GT&S rate case which authorizes an increase in the Utility's natural gas transmission and storage revenues effective as of January 1, 2011. (See "Regulatory Matters" below.)

Electric Operating Revenues

The Utility's electric operating revenues consist of amounts charged to customers for electricity generation and for electric transmission and distribution services, as well as amounts charged to customers to recover the cost of electric procurement, public purpose, energy efficiency, and demand response programs. The Utility provides electricity to residential, industrial, agricultural, and small and large commercial customers through its own generation facilities and through power purchase agreements with third parties. In addition, a portion of the Utility's customers' load is satisfied by electricity provided under long-term contracts between the California Department of Water Resources ("DWR") and various power suppliers. The commodity costs and associated revenues to recover the costs allocated to the Utility by the DWR are not included in the Condensed Consolidated Statements of Income.

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

(in millions)	Three months ended March 31,	
	2011	2010
Revenues excluding pass-through costs	\$ 1,523	\$ 1,443
Revenues for recovery of passed-through costs	1,093	1,067
Total electric operating revenues	\$ 2,616	\$ 2,510

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, increased by \$106 million, or 4%, in the three months ended March 31, 2011, as compared to the same period in 2010. Costs that are passed through to customers and do not impact net income increased by \$26 million, primarily due to increases in the cost of public purpose programs and pension contributions which were partially offset by decreases in the cost of electricity procurement. (See "Cost of Electricity" below.) Electric operating revenues, excluding costs passed through to customers, increased by \$80 million. This was primarily due to increases in authorized rate base for separately funded projects and an increase in electric transmission revenues as authorized by the FERC in an electric transmission owner ("TO") rate case.

The Utility's future electric operating revenues are expected to be impacted by the CPUC's authorized decision in the 2011 GRC and the FERC in other TO rate cases. (See "Regulatory Matters" below.) The Utility also expects to continue to collect revenue requirements outside of the GRC that are related to capital expenditures that have already been approved by the CPUC or that may be approved by the CPUC in the future. Finally, the Utility may earn incentive revenues under the existing energy efficiency ratemaking mechanism.

Cost of Electricity

The Utility's cost of electricity includes costs to purchase power from third parties, certain transmission costs, the cost of fuel used in its own generation facilities, the cost of fuel supplied to other facilities under tolling agreements and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.) The Utility's cost of electricity is passed through to customers. The Utility's cost of electricity excludes non-fuel costs associated with operating the Utility's own generation facilities, which are included in operating and maintenance expense in the Condensed Consolidated Statements of Income.

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The following table provides a summary of the Utility's cost of electricity and the total amount and average cost of purchased power:

(in millions)	Three months ended March 31,	
	2011	2010
Cost of purchased power	\$ 821	\$ 842
Fuel used in own generation facilities	67	78
Total cost of electricity	\$ 888	\$ 920
Average cost of purchased power per kWh ⁽¹⁾	\$ 0.094	\$ 0.083
Total purchased power (in kWh)	8,779	10,117

⁽¹⁾ Kilowatt-hour

The Utility's total cost of electricity decreased by \$32 million, or 3%, in the three months ended March 31, 2011 as compared to the same period in 2010. This was caused by decreases in the volume of purchased power and the cost of fuel used in the Utility's own generation facilities. The volume of purchased power is driven by customer demand, the availability of the Utility's own electricity generation, and the cost-effectiveness of each source of electricity.

Various factors will affect the Utility's future cost of electricity, including the market prices for electricity and natural gas, the availability of Utility-owned generation, and changes in customer demand. Additionally, the cost of electricity is expected to be impacted by the higher cost of procuring renewable energy as the Utility increases the amount of its renewable energy deliveries to comply with current and future California law and regulatory requirements. The Utility expects that it will be able to continue passing through the costs of its renewable energy purchase commitments to customers. (See "Environmental Matters" below.)

The Utility's future cost of electricity also will be affected by federal or state legislation or rules that may be adopted to regulate GHG emissions. (See "Environmental Matters" below.)

Natural Gas Operating Revenues

The Utility sells natural gas and natural gas transportation services. The Utility transports gas throughout its service territory, both by using its distribution system to deliver to end-use customers, as well as to large end-use customers who are connected directly to the transmission system. In addition, the Utility delivers natural gas to off-system markets, primarily in southern California.

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

(in millions)	Three months ended March 31,	
	2011	2010
Revenues excluding pass-through costs	\$ 404	\$ 414
Revenues for recovery of passed-through costs	576	551
Total natural gas operating revenues	\$ 980	\$ 965

The Utility's natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, increased by \$15 million, or 2%, in the three months ended March 31, 2011 as compared to the same period in 2010. This reflects a \$25 million increase in the costs which are passed through to customers and do not impact net income, primarily due to an increase in the costs of natural gas procurement, public purpose programs, and pension contributions. Natural gas operating revenues, excluding costs passed through to customers, decreased by \$10 million, primarily due to a decrease in natural gas storage revenues.

The CPUC's final decision in the 2011 GT&S rate case provides for an overall increase in the revenue requirements and rates for the Utility's gas transmission and storage services for 2011 through 2014. Natural gas operating revenues also will be impacted by the CPUC's expected decision in the 2011 GRC. (See "Regulatory Matters" below.) Additionally, the Utility may earn incentive revenues under the existing energy efficiency ratemaking mechanism. (See "Regulatory Matters" below.)

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Cost of Natural Gas

The Utility's cost of natural gas includes the purchase costs of natural gas, transportation costs on interstate pipelines, and gas storage costs, but excludes the transportation costs on intrastate pipelines for core and non-core customers, which are included in operating and maintenance expense in the Condensed Consolidated Statements of Income. The Utility's cost of natural gas also includes realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

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

(in millions)	Three months ended March 31,	
	2011	2010
Cost of natural gas sold	\$ 461	\$ 444
Transportation cost of natural gas sold	47	51
Total cost of natural gas	\$ 508	\$ 495
Average cost per Mcf ⁽¹⁾ of natural gas sold	\$ 4.52	\$ 4.67
Total natural gas sold (in millions of Mcf)	102	95

⁽¹⁾ One thousand cubic feet

The Utility's total cost of natural gas increased by \$13 million, or 3%, in the three months ended March 31, 2011 as compared to the same period in 2010. The increase was primarily due to the absence in 2011 of the \$49 million the Utility received in the first quarter of 2010 to be refunded to customers as part of a litigation settlement arising from the manipulation of the natural gas market by third parties during 1999 through 2002. The increase resulting from the settlement was partially offset by a decrease in procurement costs due to decreases in the average market price of natural gas purchased.

The Utility's future cost of natural gas will be affected by the market price of natural gas and changes in customer demand. In addition, the Utility's future cost of natural gas may be affected by federal or state legislation or rules to regulate the GHG emissions from the Utility's natural gas transportation and distribution facilities and from natural gas consumed by the Utility's customers.

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 billing and service expenses, the cost of public purpose programs, and administrative and general expenses.

The Utility's operating and maintenance expenses (including costs passed through to customers) increased by \$236 million, or 24%, in the three months ended March 31, 2011, as compared to the same period in 2010. Increases in pass-through costs include a \$23 million increase in pension plan contributions and a \$52 million increase in the cost of public purpose programs due to an increase in the level of program spending. Excluding costs passed through to customers, operating and maintenance expenses increased by \$161 million, primarily due to costs of \$51 million that the Utility incurred to comply with CPUC orders and NTSB recommendations that have been issued in connection with the investigation of the San Bruno accident (see "Natural Gas Pipeline Matters" below), \$31 million in higher costs related to more severe winter storms in 2011, and increases in other expenses, including legal, regulatory, and environmental items.

The Utility currently estimates that it will incur incremental costs associated with its natural gas transmission business ranging from \$350 million to \$550 million in 2011, including costs to complete its review and validation of pipeline records, to perform pressure tests and other tests on portions of its natural gas transmission system, to respond to regulatory proceedings, and to perform other activities related to the safety of its gas pipeline system. These cost estimates could change depending on a number of factors, including the outcome of the regulatory proceedings and investigations discussed below under "Natural Gas Pipeline Matters" and new state and federal laws that may be adopted. PG&E Corporation and the Utility are uncertain what portion of the costs the Utility may incur to respond to orders, recommendations, or new legislative requirements, would be recoverable through rates and the timing of any such recovery.

Future operating and maintenance expenses also may be affected by the amount of third party liability the Utility incurs as a result of the San Bruno accident as well as by the amount of fines the CPUC may impose on the Utility in connection with the pending investigations discussed below. (See "Natural Gas Pipeline Matters" below and Note 10 of the Notes to the Condensed Consolidated Financial Statements.) If the CPUC determines in the investigations discussed below that the Utility violated laws, rules, regulations or orders, the CPUC may impose fines or penalties on the Utility, which may be material.

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Depreciation, Amortization, and Decommissioning

The Utility's depreciation and amortization expense consists of depreciation and amortization on plant and regulatory assets, and decommissioning expenses associated with fossil and nuclear decommissioning. The Utility's depreciation, amortization, and decommissioning expenses increased by \$39 million, or 9%, in the three months ended March 31, 2011, as compared to the same period in 2010, primarily due to an increase in authorized capital additions.

The Utility's depreciation expense for future periods is expected to increase as a result of an overall increase in capital expenditures and implementation of depreciation rates authorized by the CPUC. Depreciation expense in subsequent years will be determined based on rates to be set by the CPUC in the 2011 GRC and by the FERC in future TO rate cases.

Interest Income

The Utility's interest income increased by less than \$1 million in the three months ended March 31, 2011, as compared to the same period in 2010, due to fluctuations in various regulatory balancing accounts.

The Utility's interest income in future periods will be primarily affected by changes in the balance of funds held in escrow pending resolution of the Chapter 11 disputed claims, changes in regulatory balancing accounts, and changes in interest rates. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

Interest Expense

The Utility's interest expense increased by \$15 million, or 10%, in the three months ended March 31, 2011, as compared to the same period in 2010. The increase resulted from higher interest costs due to an increase in outstanding senior notes and was partially offset by a decrease in the outstanding balance of the energy recovery bonds ("ERBs"). (See Note 4 of the Notes to the Condensed Consolidated Financial Statements.)

The Utility's interest expense in future periods will be impacted by changes in interest rates, changes in the liability for Chapter 11 disputed claims, changes in regulatory balancing accounts and regulatory assets, and changes in the amount of debt outstanding as long-term debt matures and additional long-term debt is issued. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements and "Liquidity and Financial Resources" below.)

Other Income, Net

The Utility's other income, net increased by \$23 million in the three months ended March 31, 2011, as compared to the same period in 2010. The increase was primarily due to a \$25 million decrease in other expenses as a result of costs the Utility incurred in 2010 to support a California ballot initiative that appeared on the June 2010 ballot, with no similar activity in the current year. This expense was partially offset by an \$8 million decrease in allowance for equity funds used during construction due to lower average balances of construction work in progress.

Income Tax Provision

The Utility's income tax provision decreased by \$64 million, or 33%, in the three months ended March 31, 2011, as compared to the same period in 2010. The effective tax rates were 38% and 42% for 2011 and 2010, respectively. The effective tax rate decreased in the three months ended March 31, 2011, as compared to the same period in 2010 when the Utility incurred non tax deductible lobbying expenses associated with a ballot initiative and reversed a deferred tax asset that had previously been recorded to reflect the future tax benefits attributable to the Medicare Part D subsidy after 2012, which was eliminated as part of the federal healthcare legislation passed during 2010.

PG&E Corporation, Eliminations, and Other

Operating Revenues and Expenses

PG&E Corporation's revenues consist mainly of billings to its affiliates for services rendered, all of which are eliminated in consolidation. PG&E Corporation's operating expenses consist mainly of employee compensation and payments to third parties for goods and services. Generally, PG&E Corporation's operating expenses are allocated to affiliates. These allocations are made without mark-up and are eliminated in consolidation. PG&E Corporation's interest expense relates to its 5.8% Senior Notes, and is not allocated to affiliates.

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There were no material changes to PG&E Corporation's operating income in the three months ended March 31, 2011, as compared to the same period in 2010.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations depends on the levels of its operating cash flows and access to the capital and credit markets. The levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal load and natural gas, volatility in energy commodity costs, collateral requirements related to price risk management activity, the timing and amount of tax payments or refunds, and the timing and effect of regulatory decisions and financings, among other factors. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to fund debt maturities and capital expenditures and to maintain its CPUC-authorized capital structure. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs. The CPUC authorizes the aggregate amount of long-term debt and short-term debt that the Utility may issue and authorizes the Utility to recover its related debt financing costs. The Utility has short-term borrowing authority of \$4.0 billion, including \$500 million that is restricted to certain contingencies.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund Utility equity contributions as needed for the Utility to maintain its CPUC-authorized capital structure, fund tax equity investments, and pay dividends primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets.

Credit Facilities

The following table summarizes PG&E Corporation's and the Utility's revolving credit facilities at March 31, 2011:

(in millions)	Termination Date	Facility Limit	Commercial			
			Letters of Credit Outstanding	Cash Borrowings	Paper Backup	Availability
PG&E Corporation	February 2012	\$ 187 ⁽¹⁾	\$ -	\$-	\$ -	\$ 187
Utility	February 2012	1,940 ⁽²⁾	315	-	1,019	606
Utility	February 2012	750 ⁽³⁾	N/A	-	-	750
Total credit facilities		\$ 2,877	\$ 315	\$-	\$ 1,019	\$ 1,543

⁽¹⁾ Includes an \$87 million sublimit for letters of credit and a \$100 million commitment for "swingline" loans, defined as loans that are made available on a same-day basis and are repayable in full within 30 days.

⁽²⁾ Includes a \$921 million sublimit for letters of credit and a \$200 million commitment for swingline loans.

⁽³⁾ Includes a \$75 million commitment for swingline loans.

For the three months ended March 31, 2011, the average outstanding commercial paper balance was \$735 million and the maximum outstanding balance during the quarter was \$1.2 billion. There were no cash borrowings on the revolving credit facilities in the three months ended March 31, 2011.

PG&E Corporation's and the Utility's credit agreements contain covenants that are usual and customary for credit facilities of this type, including covenants limiting liens, mergers, substantial asset sales, and other fundamental changes. Both the \$750 million and the \$1.9 billion revolving credit facilities require that the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. In addition, the \$187 million revolving credit facility agreement requires that PG&E Corporation must own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility.

At March 31, 2011, PG&E Corporation and the Utility were in compliance with all covenants under each of the revolving credit facilities listed in the table above.

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2011 Financings

During the three months ended March 31, 2011, PG&E Corporation issued 2,032,223 shares of common stock upon the exercise of employee stock options and under its 401(k) plan and Dividend Reinvestment and Stock Purchase Plan, generating \$82 million of cash.

During the three months ended March 31, 2011, the Utility received cash contributions of \$65 million from PG&E Corporation to ensure that the Utility had adequate capital to maintain the 52% common equity ratio authorized by the CPUC.

Future Financing Needs

The amount and timing of the Utility’s future financings will depend on various factors, including:

- the amount of cash internally generated through normal business operations;
- the timing and amount of forecasted capital expenditures authorized by the CPUC;
- the timing of the resolution of the Chapter 11 disputed claims and the amount of interest on these claims that the Utility will be required to pay;
- the timing and amount of payments made to third parties in connection with the San Bruno accident, and the timing and amount of related insurance recoveries;
- the timing and amount of payments related to costs incurred to comply with CPUC orders and NTSB recommendations that have been issued in connection with the San Bruno accident (see “Operating and Maintenance” above and “Natural Gas Pipeline Matters” below);
- the amount of future tax payments (see the discussion of the Tax Relief Act below under “Utility – Operating Activities”); and
- the conditions in the capital markets, and other factors. (See Notes 9 and 10 of the Notes to the Condensed Consolidated Financial Statements.)

PG&E Corporation’s future financing needs depend primarily on the timing and amount of contributions made to the Utility to maintain the Utility’s 52% common equity ratio authorized by the CPUC. PG&E Corporation anticipates issuing equity in the future to meet the Utility’s additional equity needs as it performs pipeline safety-related work (see “Natural Gas Pipeline Matters—Impact on Operations” below). PG&E Corporation also may issue debt or equity in the future to fund future tax equity investments to the extent that internally generated funds are not sufficient. (See “PG&E Corporation” below).

PG&E Corporation and the Utility have had continued access to the capital markets on reasonable terms and continue to believe that the Utility’s cash flows from operations, existing sources of liquidity, and future financings will provide adequate resources to fund operating activities, meet anticipated obligations, make payments to third parties related to the San Bruno accident, make payments related to costs incurred to comply with CPUC orders and NTSB recommendations, and finance future capital expenditures and investments.

Dividends

The following table summarizes PG&E Corporation’s and the Utility’s dividends paid during the three months ended March 31, 2011:

(in millions)	
PG&E Corporation	
Common stock dividends paid	\$ 174
Utility	
Common stock dividends paid	\$ 179
Preferred stock dividends paid	4

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On February 16, 2011, the Board of Directors of PG&E Corporation declared a dividend of \$0.455 per share, totaling \$181 million, of which \$175 million was paid on April 15, 2011, to shareholders of record on March 31, 2011. The remaining \$6 million was reinvested in the Dividend Reinvestment and Stock Purchase Plan.

On February 16, 2011, the Board of Directors of the Utility declared a dividend totaling \$3 million on its outstanding series of preferred stock, payable on May 15, 2011, to shareholders of record on April 29, 2011.

Utility

Operating Activities

The Utility's cash flows from operating activities primarily consist of receipts from customers less payments of operating expenses, other than expenses such as depreciation that do not require the use of cash.

The Utility's cash flows from operating activities for the three months ended March 31, 2011 and 2010 were as follows:

(in millions)	Three Months Ended March 31,	
	2011	2010
Net income	\$ 201	\$ 264
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	534	491
Allowance for equity funds used during construction	(20)	(28)
Deferred income taxes and tax credits, net	99	138
Other	(15)	26
Effect of changes in operating assets and liabilities:		
Accounts receivable	69	114
Inventories	65	59
Accounts payable	190	94
Income taxes receivable/payable	34	77
Other current assets and liabilities	(196)	(325)
Regulatory assets, liabilities, and balancing accounts, net	(10)	(376)
Other noncurrent assets and liabilities	144	(126)
Net cash provided by operating activities	\$ 1,095	\$ 408

In the three months ended March 31, 2011, net cash provided by operating activities increased by \$687 million compared to the same period in 2010 primarily due to a decrease of \$321 million in net collateral paid by the Utility related to price risk management activities. Collateral payables and receivables are included in other changes in noncurrent assets and liabilities and other current assets and liabilities. The remaining changes in cash flows from operating activities consisted of fluctuations in activities within the normal course of business such as power purchases and customer billings.

On December 17, 2010, the Tax Relief Act was signed into law, allowing qualified property placed into service after September 8, 2010, and before January 1, 2012, to be eligible for 100% bonus depreciation for tax purposes and allowing qualified property placed into service in 2012 to be eligible for 50% bonus depreciation for tax purposes. As a result, the Utility expects that it will not make a federal tax payment in 2011. The Utility also expects that its 2012 federal tax payment will be reduced depending on the amount and timing of the Utility's qualifying capital additions. (See "Regulatory Matters – CPUC Resolution Regarding the Tax Relief Act" below.)

Additionally, there is uncertainty around the timing and amount of payments to be made to third parties in connection with the San Bruno accident, the timing and amount of related insurance recoveries, any penalties that may be assessed, costs associated with related investigations, and costs associated with changes to pipeline management and operations.

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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 used in investing activities depends primarily upon the amount and timing of the Utility's capital expenditures, which can be affected by many factors, including the timing of regulatory approvals and the occurrence of storms and other events causing outages or damages to the Utility's infrastructure. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments.

The Utility's cash flows from investing activities for the three months ended March 31, 2011 and 2010 were as follows:

(in millions)	Three Months Ended March 31,	
	2011	2010
Capital expenditures	\$ (945)	\$ (855)
Decrease in restricted cash	132	4
Proceeds from sales and maturities of nuclear decommissioning trust investments	726	337
Purchases of nuclear decommissioning trust investments	(735)	(343)
Other	7	5
Net cash used in investing activities	\$ (815)	\$ (852)

Net cash used in investing activities decreased by \$37 million in the three months ended March 31, 2011 compared to the same period in 2010. This decrease was primarily due to \$128 million in restricted cash that was released from escrow in 2011 for settled or withdrawn Chapter 11 disputed claims with no similar release in 2010. This decrease was partially offset by an increase in capital expenditures due to the timing of payments.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. (See "Capital Expenditures" below for further discussion of expected spending and significant capital projects.)

Financing Activities

The Utility's cash flows from financing activities for the three months ended March 31, 2011 and 2010 were as follows:

(in millions)	Three Months Ended March 31,	
	2011	2010
Net issuances of commercial paper, net of discount of \$1 million in 2011	\$ 415	\$ 418
Long-term debt matured	(500)	-
Energy recovery bonds matured	(97)	(93)
Preferred stock dividends paid	(4)	(4)
Common stock dividends paid	(179)	(179)
Equity contribution	65	20
Other	21	8
Net cash provided by (used in) financing activities	\$ (279)	\$ 170

In the three months ended March 31, 2011, net cash used in financing activities increased by \$449 million compared to the same period in 2010. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities and the level of cash provided by or used in investing activities. The Utility generally utilizes long-term senior unsecured debt issuances and equity contributions from PG&E Corporation to fund debt maturities and capital expenditures and to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

PG&E Corporation

As of March 31, 2011, PG&E Corporation's affiliates had entered into four tax equity agreements with two privately held companies to fund residential and commercial retail solar energy installations. Under these agreements, PG&E Corporation agreed to provide lease payments and investment contributions of up to \$300 million to these companies in exchange for the right to receive the benefits of local rebates, federal investment tax credits or grants, and a share of the customer payments made to these

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companies. As of March 31, 2011, PG&E Corporation had made total payments of \$216 million under these tax equity agreements. On April 14, 2011, PG&E Corporation borrowed \$75 million under its \$187 million credit facility to fund the obligations under the tax equity agreements. On April 28, 2011, PG&E Corporation increased its commitment under one of the existing tax equity agreements by \$98 million. Lease payments and investment contributions are included in cash flows from operating and investing activities, respectively, within the Condensed Consolidated Statements of Cash Flows.

In addition to the investments above, PG&E Corporation had the following material cash flows on a stand-alone basis for the three months ended March 31, 2011 and 2010: dividend payments, common stock issuance, and transactions between PG&E Corporation and the Utility.

CONTRACTUAL COMMITMENTS

PG&E Corporation and the Utility enter into contractual 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 electricity and natural gas for customers, purchases of transportation capacity, purchases of renewable energy, and the purchase of fuel and transportation to support the Utility's generation activities. (Refer to the 2010 Annual Report, the "Liquidity and Financial Resources" section above and Notes 4 and 10 of the Notes to the Condensed Consolidated Financial Statements.)

CAPITAL EXPENDITURES

Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC, TO rate cases, and GT&S rate cases. (See "Regulatory Matters" below.) The Utility also collects additional revenue requirements to recover capital expenditures related to projects that have been specifically authorized by the CPUC, such as new power plants, gas or electric distribution projects, and the SmartMeter™ advanced metering infrastructure.

The Utility's proposals for significant capital projects that have been submitted for CPUC approval are discussed in the 2010 Annual Report. The GT&S rate case reflects a negotiated capital expenditure plan for 2011, 2012, 2013, and 2014 of \$177 million, \$202 million, \$168 million, and \$151 million, respectively. No other recent developments in authorized or proposed capital projects have occurred since the 2010 Annual Report was filed.

OFF-BALANCE SHEET ARRANGEMENTS

PG&E Corporation and the Utility do not have any other off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 2 (PG&E Corporation's tax equity financing agreements) and Note 10 (the Utility's commodity purchase agreements) of the Notes to the Condensed Consolidated Financial Statements.

CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies; including those related to Chapter 11 disputed claims, claims arising from the San Bruno accident, tax matters, legal matters (including regulatory investigations), and environmental matters, which are discussed in Notes 9 and 10 of the Notes to the Condensed Consolidated Financial Statements.

NATURAL GAS PIPELINE MATTERS

Following the San Bruno accident on September 9, 2010, several regulatory investigations and proceedings have been initiated involving aspects of the Utility's natural gas transmission operations, as discussed in the 2010 Annual Report. The following proceedings are currently pending:

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- The NTSB began its formal investigation of the San Bruno accident on September 10, 2010. The NTSB is responsible for investigating the San Bruno accident, determining the probable cause of the pipeline rupture, and making recommendations to prevent similar accidents from occurring. The NTSB has issued several public statements and reports regarding its investigation, but has not yet determined the cause of the pipeline rupture. The NTSB held fact-finding hearings in Washington D.C. in early March. PG&E Corporation and the Utility are currently unable to predict the outcome of the investigation and when the NTSB will issue a final report.
- The CPUC appointed an independent review panel to gather and review facts, make a technical assessment of the San Bruno accident and its root cause, and make recommendations for action by the CPUC to ensure such an accident is not repeated. The report of the independent review panel is expected in the second quarter of 2011.
- The CPUC also began an investigation of the Rancho Cordova accident. See “Pending CPUC Investigations” below.
- On February 24, 2011, the CPUC initiated a formal investigation to determine whether the Utility’s gas transmission pipeline recordkeeping and its knowledge of its own gas transmission system, particularly the pipeline involved in the San Bruno accident, was deficient. See “Pending CPUC Investigations” below.
- On February 24, 2011, the CPUC also opened a rulemaking proceeding in order to develop and adopt safety-related changes to its regulation of natural gas transmission and distribution pipelines in California. See “CPUC Rulemaking Proceeding” below.

In addition to the pending investigations and proceedings, various civil lawsuits have been filed by residents of San Bruno in California state courts against PG&E Corporation and the Utility related to the San Bruno accident. These lawsuits seek compensation for personal injury and property damage claims, damage to infrastructure, and other damage claims. See “Pending Lawsuits and Claims” below. Finally, each of the Boards of Directors of PG&E Corporation and the Utility has appointed a special review committee, composed solely of independent directors, to review the circumstances surrounding the San Bruno accident, natural gas transmission and distribution practices used in the industry and by the Utility, and such other matters as the committees deem appropriate. The committees’ reviews, which commenced in late 2010, are expected to be completed by the third quarter of 2011. PG&E Corporation and the Utility are unable to predict the outcome of the pending investigations, regulatory proceedings, and legal matters associated with the San Bruno accident and the Utility’s natural gas operations.

The Utility currently expects that it will incur a material amount of costs to comply with CPUC orders and NTSB recommendations regarding the Utility’s natural gas operations. It is uncertain what portion of these costs, if any, the Utility will be able to recover through rates and the timing of any such recovery. See “Impact on Operations” below.

Pending CPUC Investigations

Utility’s Facilities Records for its Natural Gas Pipelines

On February 24, 2011, the CPUC issued an order instituting a formal investigation (“OII”) pertaining to safety recordkeeping for the Utility’s gas transmission pipeline that ruptured in the San Bruno accident, as well as for its entire gas transmission system. The CPUC stated that in deciding to issue the OII, it had relied on the NTSB’s public preliminary reports issued in connection with its investigation of the San Bruno accident, the NTSB’s January 3, 2011 urgent safety recommendations regarding the importance of accurate pipeline records in calculating maximum safe operating pressures, and other NTSB statements. After the NTSB has completed its investigation and issued a final report, the CPUC also will consider other possible violations of law, besides recordkeeping, associated with the Utility’s transmission lines and with Line 132 in particular.

The first phase of the CPUC’s investigation will be limited to (1) whether the Utility’s gas transmission pipeline recordkeeping and its knowledge of its own transmission gas system (and, in particular, the San Bruno pipeline) was deficient and unsafe, and (2) whether the Utility thereby violated applicable law and safety standards. In particular, this phase will determine, among other matters, whether the San Bruno tragedy would have been preventable by the exercise of safe procedures and/or accurate and effective technical recordkeeping in compliance with the law. The CPUC will consider whether the Utility’s approach to recordkeeping stems from corporate-level management policies and practices and, if so, whether those management practices and policies contributed to recordkeeping violations that adversely affected safety.

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On April 18, 2011, the Utility provided information to the CPUC about the regulatory history applicable to gas transmission and recordkeeping practices, the records related to the San Bruno accident, and other information as directed by the CPUC.

By June 18, 2011, the Utility must provide the CPUC with additional information including information about the Utility's recordkeeping policies and practices, actions the Utility has taken since 1955 to promote safety on its gas transmission pipeline system, and safety risk assessments.

If the CPUC determines that the Utility violated safety law standards with respect to its gas system recordkeeping, the CPUC will schedule a later phase or phases to determine whether penalties are warranted, and if so the amount of such penalties.

Rancho Cordova Accident

Additionally, the CPUC's investigation of the Rancho Cordova accident is pending. On February 17, 2011, the Utility submitted its report to the CPUC to provide extensive information, from as far back as January 1, 2000, about the Utility's natural gas operating and maintenance practices and procedures. The Utility's report agrees with the NTSB's conclusions about the probable cause of the accident and explains what process improvements the Utility has made to prevent a similar accident in the future. The CPUC has scheduled an evidentiary hearing in mid-July.

If the CPUC determines that the Utility violated applicable laws in connection with the San Bruno or Rancho Cordova accidents, the CPUC could impose penalties of up to \$20,000 per day, per violation, which, in the aggregate, could have a material adverse impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.) In addition, law enforcement authorities could begin proceedings that could result in the imposition of civil or criminal fines or penalties on the Utility. PG&E Corporation and the Utility are unable to predict the ultimate outcome of the investigations discussed above or whether additional investigations or proceedings will be instituted.

CPUC Rulemaking Proceeding

On February 24, 2011, the CPUC opened a rulemaking proceeding in order to develop and adopt safety-related changes to its regulation of natural gas transmission and distribution pipelines, including requirements for construction, especially shut-off valves, maintenance, inspections, operation, record retention, ratemaking, and the application of penalties. Among other objectives, the CPUC stated that it intends to use the proceeding to:

- provide the public with the expert recommendations of the independent review panel appointed by the CPUC to conduct an investigation into the San Bruno accident;
- consider ways that the CPUC can undertake a comprehensive risk assessment for all natural gas pipelines regulated by the CPUC;
- consider available options for the CPUC to better align ratemaking policies, practices, and incentives to elevate safety considerations, and maintain utility management focus on the "nuts and bolts" details of prudent utility operations; and
- consider whether additional whistleblower protections are needed.

On March 15, 2011, the Utility submitted a report in response to the CPUC's order to (1) search the Utility's records for all as-built drawings, alignment sheets, and specifications, and all design, construction, inspection, testing, maintenance, and other related records, relating to pipeline system components (such as pipe segments, valves, fittings, and weld seams) for all of the Utility's natural gas transmission pipelines located in class 3 and class 4 locations and class 1 and class 2 high consequence areas ("HCA") that have not been subject to hydrostatic pressure testing to determine the pipeline's maximum allowable operating pressure ("MAOP") and (2) use the located records to determine the MAOP of these pipelines, based on the weakest section of the pipeline or component. (The CPUC's order was originally issued on January 3, 2011 following the NTSB's urgent safety recommendations regarding the importance of accurate pipeline records in calculating maximum safe operating pressures.) The Utility reported that it had been able to locate complete or partial records of pressure tests for approximately 1,200 miles of the 1,805 miles of pipelines, including pipelines whose MAOP was not required to be established through pressure-testing by state or federal regulations.

On March 24, 2011, the CPUC issued an order to show cause ("OSC") why the Utility should not be penalized for failing to present evidence that it "aggressively and diligently searched" its records. On April 11, 2011, the CPUC held oral arguments related to a proposed stipulation between the CPUC's Consumer Protection and Safety Division ("CPSD") and the Utility to resolve the OSC by establishing a detailed compliance plan including specific milestones for the Utility to meet as it completes its records review and MAOP validation. The plan would require the Utility to (1) complete any additional record collection for 705 miles of pipeline that do

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not have pressure test records and (2) validate the MAOP based on the records, by August 31, 2011. The proposed compliance plan is based on an MAOP validation methodology that would supplement specific documentation with an engineering analysis, excavation and field testing, and assumptions about certain pipeline components, such as fittings and elbows, based on the material specifications at the time those materials were procured. On April 26, 2011, the CPSD notified the Utility that the proposed methodology was not sufficient and that it believes the CPUC should require pressure testing or pipe replacement whenever assumptions would be used in the Utility's validation efforts. If the CPUC concurs with the CPSD, the Utility believes that the proposed compliance plan should be revised based on a new, longer-term strategy for pressure testing and pipeline replacement.

Under the proposed stipulation the Utility would pay a penalty of \$3 million. If there is an unexcused failure by the Utility to meet any of the milestones, the Utility would be required to pay additional penalties, up to \$3 million, as the CPUC determines. The penalties would not be recoverable through rates. The proposed stipulation does not constitute an admission by the Utility of any fact alleged in the OSC or of any non-compliance or other violation of any order, rule, regulation or law. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the proposed stipulation.

By the end of June 2011, the Utility plans to submit its Pipeline 2020 program of initiatives, first announced in October 2010, to the CPUC for consideration in the rulemaking proceeding. Through the program, the Utility intends to work with regulators and industry experts to strengthen the natural gas system over the next decade. The program would focus on the modernization of critical pipeline infrastructure, the use of automatic or remotely operated shut-off valves, the development of industry-leading best practices, and enhancing public safety. On December 1, 2010, the Utility requested the CPUC to permit the Utility to establish a memorandum account so the Utility can track costs incurred under the program for possible future recovery through rates. On April 4, 2011, a draft resolution was issued which, if adopted by the CPUC, would deny the Utility's request to establish the memorandum account. Instead, the resolution proposes to allow the Utility to seek approval of the memorandum account in the rulemaking proceeding. The CPUC has indicated that the rulemaking process will be the vehicle for addressing ratemaking and cost recovery for the costs incurred by all the California gas utilities to comply with and meet the new standards.

The CPUC will hold public hearings and conduct a pre-hearing conference by the end of the second quarter of 2011. After the pre-hearing conference, a ruling will be issued to define the scope of the proceeding and set a procedural schedule.

Pending Lawsuits and Other Claims

In addition to the pending investigations and proceedings discussed above, as of March 31, 2011, 74 tort lawsuits on behalf of approximately 224 plaintiffs, including two class action lawsuits, have been filed against PG&E Corporation and the Utility. Five of the lawsuits on behalf of 11 plaintiffs were filed in the San Francisco County Superior Court; the rest were filed in San Mateo County Superior Court. These tort lawsuits seek compensation for personal injury and property damage and seek other relief. The class action lawsuits allege causes of action for strict liability, negligence, public nuisance, private nuisance, and declaratory relief. Several other residents of San Bruno also have submitted damage claims to the Utility. Another lawsuit was filed in San Mateo Superior Court as a purported shareholder derivative lawsuit to seek recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. All of these cases have been coordinated and assigned to one judge in the San Mateo County Superior Court.

The Utility recorded a provision of \$220 million in 2010 for estimated third-party claims related to the San Bruno accident, including personal injury and property damage claims, damage to infrastructure, and other damage claims. The Utility currently estimates that it may incur as much as \$400 million for third-party claims. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.) As more information becomes known, including information resulting from the NTSB and CPUC investigations, management's estimates and assumptions regarding the amount of third-party liability incurred in connection with the San Bruno accident may change. Although PG&E Corporation and the Utility currently consider it likely that a significant portion of the costs the Utility incurs for third-party claims will ultimately be covered by its liability insurance, no amounts for insurance recoveries have been recorded as of March 31, 2011.

On February 23, 2011, PG&E Corporation rejected a shareholder demand that had been made following the San Bruno accident demanding that the PG&E Corporation Board of Directors (1) institute an independent investigation of the San Bruno accident and related alleged safety issues; (2) seek recovery of all costs associated with such issues through legal proceedings against those determined to be responsible, including board members, officers, other employees, and third parties; and (3) adopt corporate governance initiatives and safety programs. The PG&E Corporation Board of Directors authorized PG&E Corporation to reject the demand as had been recommended by the Evaluation Committee, a committee composed of outside Board members that had been appointed to evaluate the demand and recommend how the Board should respond. In rejecting the demand, the Board reserved the right to commence further investigation or litigation regarding the San Bruno accident if the Board deems such investigation or litigation appropriate. In April 2011, the shareholder's counsel wrote to the Evaluation Committee's counsel requesting materials that would evidence the Board's action. The Evaluation Committee is currently considering the request.

Impact on Operations

The Utility currently estimates that it will incur incremental costs associated with its natural gas transmission business, ranging from \$350 million to \$550 million in 2011, increased from the \$200 million to \$300 million estimated range disclosed in the 2010 Annual Report. These costs are expected to include costs to complete the Utility's review and validation of pipeline records, to perform pressure tests and other tests on portions of its natural gas transmission system, to respond to regulatory proceedings, and to perform other activities related to the San Bruno accident.

These cost estimates could change depending on a number of factors, including the outcome of the regulatory proceedings and pending investigations discussed above, the outcome of the "safety phase" of the Utility's 2011 GT&S rate case (see "2011 Gas Transmission and Storage Rate Case" below), and the outcome of future rulemaking, ratemaking, or other investigatory proceedings that may be commenced at the CPUC. If state or federal legislation is enacted to address natural gas transmission operations and maintenance, the Utility may incur additional costs to comply with such new statutory requirements. Such legislation may establish operating practice standards for natural gas transmission operations and safety, which may require the use of certain types of inspection methods and equipment, and to require the installations of certain types of valves.

PG&E Corporation and the Utility are uncertain what portion of the costs, if any, the Utility may incur to respond to orders, recommendations, or new legislative requirements, would be recoverable through rates and the timing of any such recovery. The CPUC is expected to decide in the future whether the Utility's ratepayers or shareholders, or both, will pay for the Utility's costs incurred in testing, pipe replacement, or other costs. As the Utility incurs these costs, the amount of equity needed by the Utility to maintain its capital structure is anticipated to increase. (See "Liquidity and Capital Resources" above.)

Future operating and maintenance expenses also may be affected by the amount of third party liability the Utility incurs as a result of the San Bruno accident. The Utility estimates that it may incur as much as \$180 million for third-party claims related to the San Bruno accident, in addition to the \$220 million provision recorded in 2010. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.) Finally, if the CPUC determines in the pending investigations discussed above that the Utility violated laws, rules, regulations or orders, the CPUC may impose fines or penalties on the Utility, which may be material.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. Significant regulatory developments that have occurred since the 2010 Annual Report was filed with the SEC are discussed below.

2011 General Rate Case Application

On February 22, 2011, a proposed decision ("PD") and an alternate proposed decision ("APD") were issued in the Utility's 2011 GRC at the CPUC. In the GRC, the CPUC will authorize the Utility's revenue requirements for 2011 through 2013 for its costs to own and operate its electric and natural gas distribution and electric generation operations. The PD and the APD would approve the unopposed October 15, 2010 settlement agreement among the Utility, the CPUC's Division of Ratepayer Advocates ("DRA"), The Utility Reform Network ("TURN"), Aglet Consumer Alliance, and nearly all other intervening parties. The 2011 revenue requirement increase associated with the settlement agreement is \$395 million. In addition, the PD and the APD would resolve the one issue not covered in the settlement agreement, which is the Utility's request for additional revenues to recover financing costs and the return of capital related to the Utility's unrecovered investment in conventional meters that have been replaced by SmartMeter™ devices.

As shown in the table below, the Utility originally had requested an additional \$44 million in revenues in 2011 to recover the financing costs associated with its remaining \$341 million investment in conventional electric meters, based on the weighted average after-tax cost of capital of 8.79% (12.93% on a pre-tax basis) and an 18-year average remaining life for these meters. The PD would authorize an additional \$53 million in revenues in 2011, while the APD would result in an additional \$59 million in revenues.

The settlement agreement's proposed \$395 million revenue requirement increase for 2011, combined with the Utility's original request of \$44 million in revenues for the recovery of financing costs associated with conventional meters, would have resulted in an increase of \$439 million for 2011. In comparison, the PD would result in an increase of \$448 million for 2011. The APD would provide an increase of \$454 million. If either the PD or the APD is adopted, the Utility's related 2011 revenues are projected to be approximately \$3.2 billion for electric distribution, \$1.1 billion for natural gas distribution, and \$1.7 billion for electric generation operations.

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(in millions)	Settlement	Proposed Decision	Alternate Proposed Decision
Settlement Revenue Requirement Increase	\$ 395	\$ 395	\$ 395
Return on Undepreciated Meters	44	25	35
Impact of Change in Amortization Period	-	38	38
Levelization Adjustment	-	(10)	(14)
Total Revenue Requirement Increase Incremental to Settlement	44	53	59
Total Revenue Requirement Increase	\$ 439	\$ 448	\$ 454

Both the PD and the APD authorize the attrition increases proposed in the settlement agreement: an additional increase of \$180 million to the authorized 2011 revenues in 2012 and an additional increase of \$185 million in 2013. In addition, while the Utility originally had requested recovery of \$113 million for meter reading costs in 2011, both the PD and the APD authorize recovery of these costs via a new balancing account as proposed in the settlement agreement. After a final decision is issued, future revenues will be adjusted to allow the Utility to recover the authorized revenue requirements as of January 1, 2011.

Additionally, on April 5, 2011, the CPUC issued both a PD and an APD in the residential rate design portion of the Utility's 2011 GRC proceeding. If either the PD or APD are adopted, there would be less disparity between tiers which is expected to result in less volatility for customers in higher tiers.

PG&E Corporation and the Utility are unable to predict whether the CPUC will approve either the PDs or APDs, or an alternative.

Electric Transmission Owner Rate Cases

On April 28, 2011, the Utility filed with the FERC a request to approve an uncontested settlement of the Utility's electric TO rate case. The settlement, if approved, will increase the annual retail revenue requirement from \$875 million to \$934 million with rates effective as of March 1, 2011. The Utility has held adequate reserves for refund for the difference between revenues collected at the higher as-filed rates and the rates included in the settlement since March 1, 2011. It is expected that FERC will act on the settlement before the end of 2011.

2011 Gas Transmission and Storage Rate Case

On April 14, 2011, the CPUC issued a final decision that approves the settlement agreement, known as the Gas Accord V Settlement Agreement ("Gas Accord V"), entered into among the Utility and other parties to determine the rates and terms and conditions of the Utility's gas transmission and storage services for a four-year period beginning January 1, 2011. The decision also resolves several objections raised by the other two California gas utilities.

The CPUC authorized a 2011 natural gas transmission and storage revenue requirement of \$514 million, an increase of \$52 million over the 2010 adopted revenue requirement. With attrition increases, the Utility's revenue requirements for 2012, 2013, and 2014 will be \$541 million, \$565 million, and \$582 million, respectively. The Utility also has been authorized to recover (through natural gas transmission and storage rates) revenue requirements for other costs, such as the cost of electricity used to operate natural gas compressor stations and other costs, that are determined in the Utility's 2011 General Rate Case or other Utility regulatory proceedings. Customer rates for the remainder of 2011 will be adjusted to allow the Utility to recover the authorized revenue requirements from January 1, 2011.

The decision also requires the Utility to file a semi-annual safety report, beginning October 1, 2011, with the CPUC's Energy Division and the CPSD to provide details about the Utility's use of funds budgeted for pipeline safety, reliability and integrity projects and activities, including an explanation of whether the Utility has under-spent or over-spent funds. The reports will provide CPUC staff with the necessary details to: (1) monitor what storage and pipeline-related safety, reliability, and integrity capital projects and maintenance activities are being undertaken by the Utility and the amounts spent on such activities, (2) determine whether projects that have been identified by the Utility with high risk assessments are being carried out or whether other higher risk projects have been undertaken instead, (3) determine the Utility's rationale for reprioritization of projects, and (4) monitor the status of the Utility's compliance with federal regulations.

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The CPUC also established a “safety phase” of the GT&S case to address safety-related concerns involving actions that can be taken during the rate cycle period covered by the GT&S rate case. PG&E Corporation and the Utility anticipate that the CPUC will issue a final decision in the “safety phase” before the end of the second quarter of 2011.

Energy Efficiency Programs and Incentive Ratemaking

On November 15, 2010, a proposed decision was issued that if, adopted by the CPUC, would modify the incentive mechanism that would apply to the 2010 through 2012 program cycle. Among other changes, the proposed modification would limit the total amount of the incentive award or penalty that could be awarded to, or imposed on, all the investor-owned utilities to \$189 million. If the proposed decision is adopted, the Utility’s opportunity to earn incentive revenues would be limited compared to the mechanism that was in place for the 2006-2008 program cycle. The proposed decision notes that the CPUC may establish a new rule-making proceeding to determine what mechanism, if any, will apply to programs beginning in 2013 and later.

Additionally, on March 17, 2011, the California Legislature adopted Senate Bill 69 (“SB 69”) which proposes the transfer of up to \$155 million from the gas-consumption surcharge fund to the California General State Fund to help close the state’s fiscal-year 2011-2012 budget gap. The surcharge is collected to help fund gas public purpose programs, including energy efficiency programs. If the methodology adopted by the CPUC for allocating the split amongst the IOUs is based on energy efficiency programs, the Utility’s share is estimated to be up to \$64 million. The Utility’s two year 2011-2012 budget for gas energy efficiency programs is \$892 million, of which approximately \$160 million was expected to be funded by the gas surcharge funds. If SB 69 is signed by the Governor and becomes effective, PG&E Corporation’s and the Utility’s results of operations could be adversely affected if the CPUC does not permit the Utility to curtail spending on some of the programs or to recover the shortfall in program funding through rates. In addition, it is unclear how SB 69 would affect the proposal to modify the incentive mechanism for the 2010 through 2012 program cycle.

CPUC Resolution Regarding the Tax Relief Act

On April 14, 2011, the CPUC adopted a resolution establishing a one-way memorandum account for certain rate-regulated utilities, including the Utility, to record the net change in the cost of providing utility service associated with the Tax Relief Act. For qualified property placed into service after September 8, 2010 and before January 1, 2012, the Tax Relief Act allows the Utility to take a tax deduction for the entire cost of its investment in the same year that the property was placed into service. For qualified property placed into service in 2012 (as well as a portion of the investment on certain property placed into service in 2013 if construction had begun before January 1, 2013) the Utility may take a deduction for one-half of the cost of the investment in the same year that the property was placed into service with the remaining investment cost recovered over a normal depreciation period. As a result of the accelerated depreciation the Utility’s federal tax payments are expected to be lower allowing the Utility to use the increased cash for additional capital investments. The memorandum account will track: (1) the reduction in revenue requirements that is due to lower rate base resulting from deferred tax liabilities related to the accelerated federal tax depreciation, (2) the increase in revenue requirements associated with incremental capital investments that are made on behalf of Utility customers, and (3) other applicable reductions and increases in revenue requirements.

The memorandum account will be applicable to CPUC-jurisdictional assets only; however, it is expected to exclude investments that have separate ratemaking treatment such as the Utility’s program to install an advanced metering system. The net benefits of the Tax Relief Act related to those excluded investments will automatically flow to customers under existing balancing account mechanisms. The memorandum account will be in effect for capital investments (other than those related to natural gas transmission operations) until 2014, the test year of the Utility’s next general rate case. The memorandum account will be in effect for capital investments related to natural gas transmission operations until 2015, the test year for the Utility’s next gas transmission and storage rate case. In each rate case, the CPUC will determine the disposition of the memorandum account.

Deployment of SmartMeter™ Technology

The CPUC has authorized the Utility's program to install approximately 10 million advanced electric and gas meters throughout the Utility's service territory by the end of 2012. Advanced electric meters, which record energy usage in hourly or quarter-hourly increments, allow customers to track energy usage throughout the billing month and thus enable greater customer control over electricity costs. Usage data is collected through a wireless communication network and transmitted to the Utility's information system where the data is stored and used for billing and other Utility business purposes. Advanced electric meters enable the implementation of "dynamic pricing" rates for customers that reflect the higher cost of electricity during periods of high demand. As of March 31, 2011, the Utility has installed 7.8 million meters. The CPUC has authorized the Utility to recover a maximum of \$2.3 billion in estimated project costs. Costs that exceed \$2.3 billion will not be recoverable through rates. As of March 31, 2011, the Utility has incurred costs of \$2.1 billion. The Utility has also recorded a provision of \$36 million as of March 31, 2011 and December 31, 2010, representing the current forecast of capital-related costs that are expected to exceed the CPUC-authorized cost cap and therefore will not be recoverable through rates. The Utility will update its forecasts as the project continues and may incur additional non-recoverable costs.

On March 24, 2011, the Utility filed an application with the CPUC to seek approval of the Utility's proposal to provide residential customers the option to turn off the radios in their gas and electric SmartMeter™ devices to disable the radio frequency ("RF") communications used in the wireless meters. The Utility requested that the CPUC authorize electric and gas revenue requirements totaling \$84.4 million through 2013 to recover the Utility's estimated costs to provide the "radio-off" option which would be collected through fees charged to customers who choose the radio-off option. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the Utility's proposal.

Additionally, on April 11, 2011, the Kern County Superior Court in Bakersfield, California dismissed the pending class action complaint that had alleged that the SmartMeter™ system generated inaccurate bills and led to overcharges, among other allegations.

Diablo Canyon Relicensing Application

The NRC operating license for Diablo Canyon Unit 1 expires in November 2024 and the NRC operating license for Diablo Canyon Unit 2 expires in August 2025. On November 24, 2009, the Utility filed an application to request the NRC to renew each of the operating licenses for Diablo Canyon for 20 years, until November 2044 for Unit 1 and August 2045 for Unit 2. The license renewal process is expected to take several years as the NRC holds public hearings and conducts safety and environmental analyses and site audits. The Utility's application has been challenged by local environmental and anti-nuclear power organizations and the NRC is considering whether to admit their contentions for further review in the renewal process. Further, in response to the significant damage to the nuclear facilities in Japan caused by the recent earthquake and tsunami, there has been increased public concern expressed about the seismic safety of Diablo Canyon. On April 11, 2011, the Utility requested that the NRC delay final action on the Utility's renewal application until after the Utility completes additional seismic studies and submits a report to the NRC addressing the results of those studies. The Utility also announced that it is seeking to obtain required permits from various local regulatory agencies on an expedited basis to accelerate the completion of the seismic studies. Finally, on April 14, 2011, petitions were filed with the NRC requesting that the NRC immediately suspend all nuclear licensing and re-licensing activities until it completes a thorough investigation into the adequacy of federal safety and environmental standards and the NRC determines whether new regulations are required. Additionally, on April 14, 2011, a motion was filed with the CPUC requesting the dismissal of the Utility's application to recover the costs associated with renewal of the Diablo Canyon operating licenses. The Utility estimates that these costs will total \$85 million.

PG&E Corporation and the Utility are unable to predict how long the NRC process will be delayed, whether the NRC will approve the license renewal application, or whether the NRC will suspend the license renewal process. (See Item 1A. Risk Factors, below.)

ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. (See "Risk Factors" in the 2010 Annual Report.) These laws and requirements relate to a broad range of the Utility's activities, including the discharge of pollutants into the air, water, and soil; the transportation, handling, storage, and disposal of spent nuclear fuel; remediation of hazardous wastes; and the reporting and reduction of carbon dioxide and other GHG emissions. Significant developments that have occurred since the 2010 Annual Report was filed with the Securities and Exchange Commission are discussed below.

Climate Change

The California Global Warming Solutions Act of 2006 (also known as Assembly Bill 32 or "AB 32") requires the gradual reduction of GHG emissions in California to the 1990 levels by 2020 on a schedule beginning in 2012. In December 2008, the California Air Resources Board ("CARB") adopted a scoping plan that contains recommendations for achieving the maximum technologically feasible and cost-effective GHG reductions to meet the 2020 reduction target, including a proposed cap-and-trade program. On March 18, 2011, the San Francisco County Superior Court ruled that the CARB had failed to comply with the California Environmental Quality Act ("CEQA") because the CARB did not adequately review and analyze alternatives to the measures identified in its scoping plan. The court prohibited the CARB from implementing any of the measures contained in the scoping plan until it complies with the CEQA requirements. As a result, the implementation of the CARB's proposed cap-and-trade system may be delayed beyond the planned effective date of January 1, 2012.

Renewable Energy Resources

On April 12, 2011, the California Governor signed new legislation establishing a new renewable portfolio standard ("RPS") that increases the amount of renewable energy that retail sellers of electricity, such as the Utility, must deliver to their customers from at least 20% of their total retail sales by the end of 2010, as required by the prior law, to 33% of their total retail sales by the end of 2020. The new legislation will become effective 90 days after the current special session of the California Legislature ends. In response to the enactment of the new RPS law, the CARB is expected to abandon its regulatory efforts to establish a 33% renewable energy standard.

Under the new RPS law the amount of electricity delivered from renewable energy resources must equal an average of 20% of total retail sales in 2011, 2012 and 2013, at least 25% of total retail sales by December 31, 2016, and at least 33% of total retail sales by December 31, 2020. The CPUC is authorized to set interim procurement targets for all other intervening years to reflect reasonable progress toward the statutory goals. The CPUC must determine by no later than January 1, 2012, the total procurement requirement (expressed as a percentage of total retail sales) for each retail seller, including the Utility, in each future compliance period (i.e., 2011-2013, 2014-2016, 2017-2020, and each year thereafter). The Utility expects that the CPUC's rulemaking in response to the new legislation will more definitively establish the Utility's RPS compliance obligations, including a cap on the Utility's total mandated RPS compliance expenditures.

The new RPS legislation creates three distinct categories of renewable energy products and imposes minimum or maximum procurement targets for each of these product categories that must be met in each future compliance period. With certain exceptions, these categorical requirements will only apply to contracts that are entered into after June 1, 2010. The new law imposes limits on the types of tradable renewable energy credits ("REC"s) that can be used to satisfy the categorical requirements and contains new restrictions on the Utility's ability to carry forward (or "bank") RPS volumes from contracts with terms of less than ten years. The new legislation requires that the CPUC approve applications for utility-owned renewable generation up to a certain energy-based cap, provided that the CPUC finds that the cost of the application is reasonable and meets other conditions. The costs of utility-owned renewable generation projects will be subject to traditional cost-of-service ratemaking treatment.

Under the new RPS law, the CPUC must waive enforcement of the RPS requirements as to any particular retail seller if it finds that certain specified circumstances beyond the control of the retail seller will prevent compliance and the retail seller has met certain other conditions, including demonstrating that the retail seller has taken all reasonable actions under its control to achieve full compliance.

Until the CPUC adopts regulations to implement the new law, it is uncertain how the CPUC's regulations and decisions issued pursuant to the former 20% RPS statute will apply to the new RPS requirements.

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Water Quality

Section 316(b) of the federal Clean Water Act requires that cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, reflect the best technology available to minimize adverse environmental impacts. On March 28, 2011, the U.S. Environmental Protection Agency (“EPA”) issued draft regulations that propose specific reductions for impingement (which occurs when larger organisms are caught on water filter screens) and provide a case-by-case site specific assessment to establish compliance requirements for entrainment (which occurs when organisms are drawn through the cooling water system). The proposed site specific assessment allows for the consideration of a variety of factors including social costs and benefits, energy reliability, land availability, and non-water quality adverse impacts. The draft regulations are subject to public comment and final regulations are not expected until July 2012.

The California Water Resources Control Board (“Water Board”) also has adopted a policy on once-through cooling. The policy, effective October 1, 2010, generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities by at least 85%. However, with respect to the state’s nuclear power generation facilities, the policy allows other compliance measures to be taken if the costs to install cooling towers are “wholly out of proportion” to the costs considered by the Water Board in developing its policy or if the installation of cooling towers would be “wholly unreasonable” after considering non-cost factors such as engineering and permitting constraints and adverse environmental impacts. The Utility believes that the costs to install cooling towers at Diablo Canyon, which could be as much as \$4.5 billion, will meet the “wholly out of proportion” test. The Utility also believes that the installation of cooling towers at Diablo Canyon would be “wholly unreasonable.” If the Water Board disagreed and if the installation of cooling towers at Diablo Canyon were not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. Assuming the Water Board does not require the installation of cooling towers at Diablo Canyon, the Utility could incur significant costs to comply with alternative compliance measures or to make payments to support various environmental mitigation projects. The Utility would seek to recover such costs in rates. The Utility’s Diablo Canyon operations must be in compliance with the Water Board’s policy by December 31, 2024.

Remediation

The Utility has been, and may be, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. These sites include former manufactured gas plant (“MGP”) sites, current and former power plant sites, former gas gathering and gas storage sites, sites where natural gas compressor stations are located, current and former substations, service center and general construction yard sites, and sites currently and formerly used by the Utility for the storage, recycling, or disposal of hazardous substances. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements, for a discussion of estimated environmental remediation liabilities and Legal Proceedings of Part II, Item 1 for discussion of related legal proceedings.)

LEGAL MATTERS

In addition to the provision made for claims related to the San Bruno accident, PG&E Corporation’s and the Utility’s Condensed Consolidated Financial Statements also include provisions for claims and lawsuits that have arisen in the ordinary course of business, regulatory proceedings, and other legal matters. See “Legal Matters” in Note 10 of the Notes to the Condensed Consolidated Financial Statements.

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; their financing arrangements; the marketplace for electricity, natural gas, electricity transmission, natural gas transportation, and storage; other goods and services; and other aspects of their businesses. PG&E Corporation and the Utility categorize market risks as “price risk” and “interest rate risk.” The Utility is also exposed to “credit risk,” the risk that counterparties fail to perform their contractual obligations.

The Utility actively manages market risks through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility’s risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

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On July 21, 2010, President Obama signed into law new federal financial reform legislation, the Dodd-Frank Wall Street Reform and Consumer Protection Act. PG&E Corporation and the Utility are evaluating the new legislation, and will review future regulations to assess compliance requirements as well as potential impacts on the Utility's procurement activities and risk management programs.

Price Risk

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long as the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings but may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's natural gas transportation and storage costs for non-core customers may not be fully recoverable. The Utility is subject to price and volumetric risk for the portion of intrastate natural gas transportation and storage capacity that has not been sold under long-term contracts providing for the recovery of all fixed costs through the collection of fixed reservation charges. The Utility sells most of its capacity based on the volume of gas that the Utility's customers actually ship, which exposes the Utility to volumetric risk.

The Utility uses value-at-risk to measure the shareholders' exposure to price and volumetric risks resulting from variability in the price of, and demand for, natural gas transportation and storage services that could impact revenues due to changes in market prices and customer demand. 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 95% confidence level, which means that there is a 5% 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 that may not adequately capture portfolio risk.

The Utility's value-at-risk calculated under the methodology described above was \$9 million at March 31, 2011. The Utility's high, low, and average values-at-risk during the 12 months ended March 31, 2011 were \$20 million, \$8 million, and \$13 million, respectively. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements for further discussion of price risk management activities.)

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 March 31, 2011, if interest rates changed by 1% for all current PG&E Corporation and the Utility variable rate and short-term debt and investments, the change would affect net income for the next 12 months by \$11.8 million, based on net variable rate debt and other interest rate-sensitive instruments outstanding.

Credit Risk

The Utility conducts business with counterparties mainly in the energy industry, including other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricity or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility ties many energy contracts to master commodity enabling agreements that may require security (referred to as "Credit Collateral" in the table below). Credit Collateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deemed appropriate by the Utility). Credit Collateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

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The following table summarizes the Utility's net credit risk exposure to its counterparties, as well as the Utility's credit risk exposure to counterparties accounting for greater than 10% net credit exposure, as of March 31, 2011 and December 31, 2010:

(in millions)	Gross Credit Exposure Before Credit Collateral ⁽¹⁾	Credit Collateral	Net Credit Exposure ⁽²⁾	Number of Wholesale Customers or Counterparties >10%	Net Exposure to Wholesale Customers or Counterparties >10%
March 31, 2011	\$ 307	\$ 17	\$ 290	2	\$ 192
December 31, 2010	\$ 269	\$ 17	\$ 252	2	\$ 187

⁽¹⁾ Gross credit exposure equals mark-to-market value on physically and 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.

⁽²⁾ Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit). For purposes of this table, parental guarantees are not included as part of the calculation.

CRITICAL ACCOUNTING POLICIES

The preparation of Condensed Consolidated Financial Statements in accordance with U.S. generally accepted accounting principles involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The accounting policies described below are considered to be critical accounting policies, due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. In addition, management has made significant estimates and assumptions about accruals related to the San Bruno accident as well as accruals for various legal matters. Actual results may differ substantially from these estimates. These policies and their key characteristics are discussed in detail in the 2010 Annual Report. They include:

- regulatory assets and liabilities;
- loss contingencies associated with legal matters and environmental remediation liabilities;
- retirement obligations; and
- pension and other postretirement plans.

For the three months ended March 31, 2011, there were no changes in the methodology for computing critical accounting estimates and no material changes to the important assumptions underlying the critical accounting estimates.

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 activities for non-trading purposes only. Both PG&E Corporation and the Utility may engage in these price risk management activities using forward contracts, futures, options, and swaps to hedge the impact of market fluctuations on energy commodity prices and interest rates (see "Risk Management Activities" above under 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 March 31, 2011, 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 to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934 ("1934 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 1934 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.

There were no changes in internal control over financial reporting that occurred during the quarter ended March 31, 2011 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

PART II. OTHER INFORMATION**ITEM 1. LEGAL PROCEEDINGS**

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's liability for legal matters, see Note 10 of the Notes to the Consolidated Financial Statements, which discussion is incorporated into this Item 1 by reference.

Diablo Canyon Power Plant

In April 2011, the United States Environmental Protection Agency ("EPA") issued revised proposed regulations under Section 316(b) of the Clean Water Act, which requires that cooling water intake structures at electric power plants reflect the best technology available to minimize adverse environmental impacts. Final regulations are expected to be issued in mid-2012, and could affect future negotiations between the state Water Board and the Utility regarding the status of the 2003 settlement agreement concerning a proposed draft Cease and Desist Order issued by the Water Board against the Utility. For more information about the settlement agreement and federal and state water quality regulations affecting Diablo Canyon, see PG&E Corporation's and the Utility's joint Annual Report on Form 10-K for the year ended December 31, 2010.

PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse impact on the Utility's financial condition or results of operations.

Hinkley Natural Gas Compressor Station

As previously disclosed, groundwater at the Utility's Hinkley natural gas compressor station contains hexavalent chromium as a result of the Utility's past operating practices. At the Hinkley site, the Utility is cooperating with the Regional Water Quality Control Board ("RWQCB") to evaluate and remediate the chromium groundwater plume. Measures have been implemented to control movement of the plume, while full-scale in-situ treatment systems operate to reduce the mass of the plume. An evaluation of the performance of these interim remedy measures, as well as possible future measures, is underway as part of the development of a final remediation plan. In March 2011, the RWQCB advised the Utility that it is considering assessing administrative penalties of up to \$5,000 per day due to the Utility's alleged violation of an administrative order issued in 2008 requiring the Utility to control the spread of the chromium groundwater plume beyond boundaries described in the order. The Utility does not believe it is in violation of the order and is working with the RWQCB to resolve its concerns. PG&E Corporation and the Utility believe that the ultimate outcome of this matter will not have a material adverse impact on the Utility's financial condition or results of operations.

Litigation Related to the San Bruno Accident

As of March 31, 2011, 74 tort lawsuits on behalf of approximately 224 plaintiffs, including two class action lawsuits, have been filed against PG&E Corporation and the Utility. Five of the lawsuits were filed in San Francisco County Superior Court; the rest were filed in San Mateo County Superior Court. These lawsuits seek compensation for personal injury and property damage and seek other relief. The class action lawsuits allege causes of action for strict liability, negligence, public nuisance, private nuisance, and declaratory relief. Several other residents of San Bruno also have submitted damage claims to the Utility. The Utility's petition to coordinate these lawsuits in San Mateo County Superior Court has been granted.

Another lawsuit was filed in San Mateo County Superior Court as a purported shareholder derivative lawsuit to seek recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. This case has been included in the coordinated proceedings described above.

The Utility maintains liability insurance for damages in the approximate amount of \$992 million in excess of a \$10 million deductible. Although PG&E Corporation and the Utility currently consider it likely that a significant portion of the costs the Utility incurs for third-party claims relating to the San Bruno accident will ultimately be covered by this insurance, no amounts for insurance recoveries have been recorded as of March 31, 2011. PG&E Corporation and the Utility are unable to predict the amount and timing of insurance recoveries.

For more information regarding the San Bruno accident and the related NTSB and CPUC investigations, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Natural Gas Pipeline Matters" and Note 10 of the Notes to the Condensed Consolidated Financial Statements.

ITEM 1A. RISK FACTORS

The risk factors appearing in the 2010 Annual Report under the headings set forth below are supplemented and updated as follows:

The ultimate amount of loss the Utility bears in connection with the San Bruno accident could have a material adverse impact on PG&E Corporation's and the Utility's financial condition and results of operations.

On February 24, 2011, the CPUC initiated a formal investigation pertaining to safety recordkeeping for the Utility's gas transmission pipeline that ruptured in San Bruno on September 9, 2010, as well as for its entire gas transmission system. If the CPUC determines that the Utility violated safety law standards with respect to its gas system recordkeeping, the CPUC may impose penalties on the Utility. If supported by the evidence, the CPUC stated that it will consider ordering daily fines for a significant period of time. (See the section of this report entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations – Natural Gas Pipeline Matters" above for more information.)

PG&E Corporation and the Utility are unable to predict whether the outcome of the investigation will have a material adverse effect on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

If the Utility cannot timely meet the applicable resource adequacy or renewable energy requirements, the Utility may be subject to penalties. Further, the CPUC may disallow costs incurred by the Utility under power purchase agreements it enters into to meet applicable resource adequacy and renewable energy requirements if the CPUC finds that the costs are unreasonably above-market in the future.

On April 12, 2011, the California Governor signed new legislation that increases the amount of renewable energy that retail sellers of electricity, such as the Utility, must deliver to their customers from at least 20% of their total retail sales by the end of 2010, as required by the prior law, to 33% of their total retail sales by the end of 2020. (See the section of this report entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Matters – Renewable Energy Resources" above.) PG&E Corporation and the Utility are unable to predict how or when the CPUC may fully implement the requirements in the new law. Until the CPUC adopts regulations to implement the new law, it is uncertain how the CPUC's regulations and decisions issued pursuant to the former 20% RPS statute will apply to the new RPS requirements. In particular, it is uncertain whether the CPUC will continue to limit penalties for noncompliance to \$25 million per year as had applied under the prior RPS regulatory program.

The operation and decommissioning of the Utility's nuclear power plants expose it to potentially significant liabilities and capital expenditures that it may not be able to recover from its insurance or other sources, adversely affecting its financial condition, results of operations, and cash flow.

As a result of the earthquake and tsunami that occurred in Japan that seriously damaged nuclear generation facilities there has been increased legislative, regulatory, and public scrutiny of the safety of nuclear power plants in the United States. The NRC has begun to review the industry's preparedness for events similar to the events that occurred in Japan and has established a senior level agency task force to conduct a systematic review of NRC processes and regulations and evaluate whether enhancements or new regulations are needed. There has been increased public concern expressed about the safety of the Utility's Diablo Canyon nuclear generation facilities located along the coastline in San Luis Obispo, California, which is in close proximity to active earthquake fault lines. On April 11, 2011, the Utility requested that the NRC delay final action on the Utility's application to renew the operating licenses for Diablo Canyon Units 1 and 2 that are scheduled to expire in 2024 and 2025 until after the Utility completes new seismic studies and submits a report to the NRC addressing the results of those studies.

The Utility may be required to incur additional capital expenditures and other expenses to address any new seismic safety requirements, backup power requirements, or other requirements that the NRC may impose following its regulatory review or following the submission of the completed seismic studies for Diablo Canyon. The NRC may order the Utility to cease its nuclear operations until any such safety concerns are addressed or the NRC may determine that the safety concerns cannot be addressed and order the Utility to cease operating Diablo Canyon. Alternatively, the Utility may determine that the safety concerns cannot be remedied in a feasible and economic manner and voluntarily cease operations at Diablo Canyon. Further, depending on the results of the license renewal process, the NRC could deny the license renewal applications requiring nuclear operations to cease when the current licenses expire.

In addition the Utility may incur significant additional expense to comply with more stringent laws and regulations that may be adopted by the NRC regarding the storage, handling, security, and disposal of radioactive materials, including spent nuclear fuel. If the Utility determines that it cannot comply with such new laws or regulations in a feasible and economic manner it may voluntarily cease operations at Diablo Canyon.

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If the Utility is unable to recover costs it incurs to respond to safety concerns or if the Utility ceased its nuclear operations, PG&E Corporation's and the Utility's financial condition, results of operations and cash flows could be materially and adversely affected.

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

During the quarter ended March 31, 2011, PG&E Corporation made equity contributions totaling \$65 million to the Utility in order to maintain the 52% common equity component of its CPUC-authorized capital structure and to ensure that the Utility has adequate capital to fund its capital expenditures. Neither PG&E Corporation nor the Utility made any sales of unregistered equity securities during the quarter ended March 31, 2011.

Issuer Purchases of Equity Securities

During the quarter ended March 31, 2011, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended March 31, 2011, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 5. OTHER INFORMATION

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

The Utility's earnings to fixed charges ratio for the three months ended March 31, 2011 was 2.56. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three months ended March 31, 2011 was 2.51. 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 333-172394 relating to various series of the Utility's first preferred stock and its senior notes, respectively.

PG&E Corporation's earnings to fixed charges ratio for the three months ended March 31, 2011 was 2.44. The statement of the foregoing ratio, together with the statement of the computation of the foregoing ratio filed as Exhibit 12.3 hereto, is included herein for the purpose of incorporating such information and Exhibit into PG&E Corporation's Registration Statement No. 333-172393 relating to its senior notes.

ITEM 6. EXHIBITS

3.1	Bylaws of PG&E Corporation amended as of May 1, 2011
3.2	Bylaws of Pacific Gas and Electric Company amended as of May 1, 2011
*10.1	Form of Restricted Stock Unit Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan
*10.2	Form of Performance Share Agreement for 2011 grants under the PG&E Corporation 2006 Long-Term Incentive Plan
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
31.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
***101.INS	XBRL Instance Document
***101.SCH	XBRL Taxonomy Extension Schema Document
***101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
***101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
***101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
***101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
*	Management contract or compensatory agreement.
**	Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.
***	Pursuant to Rule 406T of SEC Regulation S-T, these interactive data files are deemed not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933 or Section 18 of the Securities Exchange Act of 1934 and otherwise are not subject to liability under these sections. These files are being submitted only by PG&E Corporation and not by its subsidiary, Pacific Gas and Electric Company.

SIGNATURES

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

PG&E CORPORATION

KENT M. HARVEY

Kent M. Harvey
Senior Vice President and Chief Financial Officer
(duly authorized officer and principal financial officer)

PACIFIC GAS AND ELECTRIC COMPANY

SARA A. CHERRY

Sara A. Cherry
Vice President, Finance and Chief Financial Officer
(duly authorized officer and principal financial officer)

Dated: May 4, 2011

EXHIBIT INDEX

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**Bylaws
of
PG&E Corporation
amended as of May 1, 2011**

**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, the Chief Executive Officer, 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 Chief Executive Officer, the President, or the Corporate Secretary.

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

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

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

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

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

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

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

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

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

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

Article II. DIRECTORS.

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

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

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

4. **Time and Place of Directors' Meetings** . Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, the Chief Executive Officer, 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 Chief Executive Officer, 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.

9. **Majority Voting**. In any uncontested election, nominees receiving the affirmative vote of a majority of the shares represented and voting at a duly held meeting at which a quorum is present (which shares voting affirmatively also constitute at least a majority of the required quorum) shall be elected. In any election that is not an uncontested election, the nominees receiving the highest number of affirmative votes of the shares entitled to be voted for them, up to the number of directors to be elected by those shares, shall be elected; votes against a director and votes withheld shall have no legal effect.

For purposes of these Bylaws, “uncontested election” means an election of directors of the Corporation in which, at the expiration of the times fixed under Article I, Section 2 of these Bylaws requiring advance notification of director nominees, or for special meetings, at the time notice is given of the meeting at which the election is to occur, the number of nominees for election does not exceed the number of directors to be elected by the shareholders at that election.

If an incumbent director fails, in an uncontested election, to receive the vote required to be elected in accordance with this Article II, Section 9, then, unless the incumbent director has earlier resigned, the term of such incumbent director shall end on the date that is the earlier of (a) ninety (90) days after the date on which the voting results are determined pursuant to Section 707 of the California Corporations Code, or (b) the date on which the Board of Directors selects a person to fill the office held by that director in accordance with the procedures set forth in these Bylaws and Section 305 of the California Corporations Code.

Article III. OFFICERS.

1. **Officers** . The officers of the Corporation shall be elected by the Board of Directors and include a President, a Corporate Secretary, a Treasurer, or other such officers as required by law. The Board of Directors also may elect one or more Vice Presidents, Assistant Secretaries, Assistant Treasurers, and other such officers as may be appropriate, including the offices described below. Any number of offices may be held by the same person.

2. **Chairman of the Board** . The Chairman of the Board shall be a member of the Board of Directors and 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 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 Chief Executive Officer, shall exercise the Chief Executive Officer's duties and responsibilities.

3. **Vice Chairman of the Board** . The Vice Chairman of the Board shall be a member of the Board of Directors and have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. 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 shall be a member of the Board of Directors and 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. **Chief Executive Officer**. The Chief Executive Officer shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. If there be no Chairman of the Board, the Chief Executive Officer shall also exercise the duties and responsibilities of that office. The Chief Executive Officer shall have authority to sign on behalf of the Corporation agreements and instruments of every character. In the absence or disability of the President, the Chief Executive Officer shall exercise the President's duties and responsibilities.

6. **President** . The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Chief Executive Officer, or the Bylaws. If there be no Chief Executive Officer, 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.

7. **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, the Chief Executive Officer, 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 Chief Executive Officer, the President, or the Bylaws.

8. **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 Chief Executive Officer, the President, or the Bylaws.

9. **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 Chief Executive Officer, 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, the Chief Executive Officer, or the President may confer a special title upon any Vice President.

10. **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 Chief Executive Officer, 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 Chief Executive Officer, 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.

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

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

12. **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 Chief Executive Officer, 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; provided, however, that amendments to Article II, Section 9 of these Bylaws, and any other Bylaw provision that implements a majority voting standard for director elections (excepting any amendments intended to conform those Bylaw provisions to changes in applicable laws) shall be amended by the shareholders of the Corporation as provided in Section 1 of this Article V.

**Bylaws
of
Pacific Gas and Electric Company
amended as of May 1, 2011**

**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, the Chief Executive Officer, 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 Chief Executive Officer, the President or the Corporate Secretary.

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

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

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

Article II. DIRECTORS.

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

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

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

4. **Time and Place of Directors' Meetings.** Regular meetings of the Board of Directors shall be held on such days and at such times and at such locations as shall be fixed by resolution of the Board, or designated by the Chairman of the Board or, in his absence, the Vice Chairman of the Board, the Chief Executive Officer, 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 Chief Executive Officer, 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.

9. **Majority Voting.** In any uncontested election, nominees receiving the affirmative vote of a majority of the shares represented and voting at a duly held meeting at which a quorum is present (which shares voting affirmatively also constitute at least a majority of the required quorum) shall be elected. In any election that is not an uncontested election, the nominees receiving the highest number of affirmative votes of the shares entitled to be voted for them, up to the number of directors to be elected by those shares, shall be elected; votes against a director and votes withheld shall have no legal effect.

For purposes of these Bylaws, “uncontested election” means an election of directors of the Corporation in which, at the expiration of the times fixed under Article I, Section 2 of these Bylaws requiring advance notification of director nominees, or for special meetings, at the time notice is given of the meeting at which the election is to occur, the number of nominees for election does not exceed the number of directors to be elected by the shareholders at that election.

If an incumbent director fails, in an uncontested election, to receive the vote required to be elected in accordance with this Article II, Section 9, then, unless the incumbent director has earlier resigned, the term of such incumbent director shall end on the date that is the earlier of (a) ninety (90) days after the date on which the voting results are determined pursuant to Section 707 of the California Corporations Code, or (b) the date on which the Board of Directors selects a person to fill the office held by that director in accordance with the procedures set forth in these Bylaws and Section 305 of the California Corporations Code.

10. **Certain Powers Reserved to the Shareholders.** So long as PG&E Corporation shall hold the majority of the outstanding shares of the Corporation, PG&E Corporation may require the written consent of the PG&E Corporation Chairman of the Board or the PG&E Corporation Chief Executive Officer to enter into and execute any

transaction or type of transaction identified by the Board of Directors of PG&E Corporation as a “Designated Transaction.” For purposes of this Section 10, a Designated Transaction shall be any transaction or type of transaction identified in a duly adopted resolution of the Board of Directors of PG&E Corporation as requiring the written consent of the PG&E Corporation Chairman of the Board or the PG&E Corporation Chief Executive Officer pursuant to this Section 10. Notwithstanding the foregoing, nothing in this Section 10 shall limit the power of the Corporation to enter into or execute any transaction or type of transaction prior to the receipt by the Corporate Secretary of the Corporation of the resolution designating such transaction or type of transaction as a Designated Transaction pursuant to this Section 10.

Article III. OFFICERS.

1. **Officers.** The officers of the Corporation shall be elected by the Board of Directors and include a President, a Corporate Secretary, a Treasurer or other such officers as required by law. The Board of Directors also may elect one or more Vice Presidents, Assistant Secretaries, Assistant Treasurers, and such other officers as may be appropriate, including the offices described below. Any number of offices may be held by the same person.

2. **Chairman of the Board.** The Chairman of the Board shall be a member of the Board of Directors and 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 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 Chief Executive Officer, shall exercise the Chief Executive Officer’s duties and responsibilities.

3. **Vice Chairman of the Board.** The Vice Chairman of the Board shall be a member of the Board of Directors and have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. 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 shall be a member of the Board of Directors and 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. **Chief Executive Officer.** The Chief Executive Officer shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, or the Bylaws. If there be no Chairman of the Board, the Chief Executive Officer shall also exercise the duties and responsibilities of that office. The Chief Executive Officer shall have authority to sign on behalf of the Corporation agreements and instruments of every character. In the absence or disability of the President, the Chief Executive Officer shall exercise the President's duties and responsibilities.

6. **President.** The President shall have such duties and responsibilities as may be prescribed by the Board of Directors, the Chairman of the Board, the Chief Executive Officer, or the Bylaws. If there be no Chief Executive Officer, 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.

7. **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 Chief Executive Officer, 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.

8. **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 Chief Executive Officer, 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 Chief Executive Officer, 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.

9. **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 Chief Executive Officer, 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 Chief Executive Officer, the President, or the Treasurer. In the absence or disability of the Treasurer, the Treasurer's duties shall be performed by an Assistant Treasurer.

10. **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 Chief Executive Officer, the President, or the Bylaws.

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 Chief Executive Officer, 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; provided, however, that amendments to Article II, Sections 9 and 10 of these Bylaws, and any other Bylaw provision that implements a majority voting standard for director elections (excepting any amendments intended to conform those Bylaw provisions to changes in applicable laws) shall be amended by the shareholders of the Corporation as provided in Section 1 of this Article V.

PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN
RESTRICTED STOCK UNIT GRANT

PG&E CORPORATION, a California corporation, hereby grants Restricted Stock Units to the Recipient named below. The Restricted Stock Units have been granted under the PG&E Corporation 2006 Long-Term Incentive Plan, as amended (the "LTIP"). The terms and conditions of the Restricted Stock Units are set forth in this cover sheet and in the attached Restricted Stock Unit Agreement (the "Agreement").

Date of Grant: March 1, 2011

Name of Recipient: _____

Recipient's Participant ID: _____

Number of Restricted Stock Units: _____

By accepting this award, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Restricted Stock Units dated March 1, 2011.

Attachment

PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN

RESTRICTED STOCK UNIT AGREEMENT

**The LTIP and
Other
Agreements**

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock Units, subject to the terms of the LTIP. Any prior agreements, commitments, or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy, this Agreement shall govern. For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

**Grant of
Restricted Stock
Units**

PG&E Corporation grants you the number of Restricted Stock Units shown on the cover sheet of this Agreement. The Restricted Stock Units are subject to the terms and conditions of this Agreement and the LTIP.

**Vesting of
Restricted Stock
Units**

As long as you remain employed with PG&E Corporation, 20 percent of the total number of Restricted Stock Units originally subject to this Agreement, as shown above on the cover sheet, will vest on the first business day of March of each of the first, second and third years following the Date of Grant, and the additional 40 percent of the total number of shares of Restricted Stock Units will vest on the on the first business day of March of the fourth year following the Date of Grant (collectively, the "Normal Vesting Schedule"). The amounts payable upon each vesting date are hereby designated separate payments for purposes of Code Section 409A. Except as described below, all Restricted Stock Units subject to this Agreement which have not vested upon termination of your employment shall then be automatically cancelled. As set forth below, the Restricted Stock Units may vest earlier upon the occurrence of certain events.

Dividends

Restricted Stock Units will accrue Dividend Equivalents in the event cash dividends are paid with respect to PG&E Corporation common stock having a record date prior to the date on which the Restricted Stock Units are settled. Such Dividend Equivalents will be converted into cash and paid, if at all, upon settlement of the underlying Restricted Stock Units.

Settlement

Vested Restricted Stock Units will be settled in an equal number of shares of PG&E Corporation common stock, subject to the satisfaction of Withholding Taxes, as described below. PG&E Corporation shall issue shares as soon as practicable after the Restricted Stock Units vest in accordance with the Normal Vesting Schedule (but not later than sixty (60) days after the applicable vesting date); provided, however, that such issuance shall, if earlier, be made with respect to all of your outstanding vested Restricted Stock Units (after giving effect to the vesting provisions

described below) as soon as practicable after (but not later than sixty (60) days after) the earliest to occur of your (1) Disability (as defined under Code Section 409A), (2) death or (3) “separation from service,” within the meaning of Code Section 409A within 2 years following a Change in Control.

**Voluntary
Termination**

In the event of your voluntary termination (other than Retirement), all unvested Restricted Stock Units will be cancelled on the date of termination.

Retirement

In the event of your Retirement, unvested Restricted Stock Units will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement; provided, however that in the event of your Retirement within 2 years following a Change in Control, all of your Restricted Stock Units shall vest and be settled as soon as practicable after (but not later than sixty (60) days after) the date of such event. Your voluntary termination of employment will be considered to be a Retirement if you are both age 55 or older on the date of termination and if you were employed by PG&E Corporation for at least five consecutive years ending on the date of termination of your employment.

**Termination for
Cause**

If your employment with PG&E Corporation is terminated at any time by PG&E Corporation for cause, all unvested Restricted Stock Units will be cancelled on the date of termination. In general, termination for “cause” means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.

**Termination
other than for
Cause**

If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause and you are an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested during the period of the “Severance Multiple” under the Officer Severance Policy will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. In the event of your involuntary termination other than for cause, if you are not an officer in Bands 1-5, any unvested Restricted Stock Units that would have vested within the 12 months following such termination had your employment continued will continue to vest and be settled pursuant to the Normal Vesting Schedule (without regard to the requirement that you be employed), subject to the earlier settlement provisions of this Agreement. All other unvested Restricted Stock Units will be cancelled unless your termination of employment was in connection with a Change in Control as provided below.

Death/Disability

In the event of your death or Disability while you are employed, all of your Restricted Stock Units shall vest and be settled as soon as practicable after (but not later than sixty (60) days after) the date of such event. If your

death or Disability occurs following the termination of your employment and your Restricted Stock Units are then outstanding under the terms hereof, then all of your vested Restricted Stock Units plus any Restricted Stock Units that would have otherwise vested during any continued vesting period hereunder shall be settled as soon as practicable after (but not later than sixty (60) days after) the date of your death or Disability.

**Termination Due to
Disposition of
Subsidiary**

(1) If your employment is terminated (other than termination for cause, your voluntary termination, or your Retirement) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended (the “Code”), or (2) if your employment is terminated (other than termination for cause, your voluntary termination, or your Retirement) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, the Restricted Stock Units shall vest and be settled in the same manner as for a “Termination other than for Cause” described above.

**Change in
Control**

In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the “Acquiror ”), may, without your consent, either assume or continue PG&E Corporation’s rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Restricted Stock Units subject to this Agreement.

If the Restricted Stock Units are neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Restricted Stock Units, all of your unvested Restricted Stock Units shall automatically vest immediately preceding and contingent on, the Change in Control and be settled in accordance with the Normal Vesting Schedule, subject to the earlier settlement provisions of this Agreement.

**Termination In
Connection with a
Change in
Control**

If you separate from service (other than termination for cause, your voluntary termination, or your Retirement) in connection with a Change in Control within three months before the Change in Control occurs, all of your outstanding Restricted Stock Units (including Restricted Stock Units that you would have otherwise forfeited after the end of the continued vesting period) shall automatically vest on the date of the Change in Control and will be settled in accordance with the Normal Vesting Schedule (without regard to the requirement that you be employed) subject to the earlier settlement provisions of this Agreement. In the event of such a separation in connection with a Change in Control within two years following the Change in Control, your Restricted Stock Units (to the extent they did not previously vest upon, for example, failure of the Acquiror to assume or continue this Award) shall automatically vest on the date of such separation and will be settled as soon as practicable after (but not later than sixty (60) days after) the date of such separation. PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control

Delay	PG&E Corporation shall delay the issuance of any shares of common stock to the extent it is necessary to comply with Section 409A(a)(2)(B)(i) of the Code (relating to payments made to certain “key employees” of certain publicly-traded companies); in such event, any shares of common stock to which you would otherwise be entitled during the six (6) month period following the date of your “separation from service” under Section 409A (or shorter period ending on the date of your death following such separation) will instead be issued on the first business day following the expiration of the applicable delay period.
Withholding Taxes	The number of shares of PG&E Corporation common stock that you are otherwise entitled to receive upon settlement of Restricted Stock Units will be reduced by a number of shares having an aggregate Fair Market Value, as determined by PG&E Corporation, equal to the amount of any Federal, state, or local taxes of any kind required by law to be withheld by PG&E Corporation in connection with the Restricted Stock Units determined using the applicable minimum statutory withholding rates, including social security and Medicare taxes due under the Federal Insurance Contributions Act and the California State Disability Insurance tax (“Withholding Taxes”). If the withheld shares were not sufficient to satisfy your minimum Withholding Taxes, you will be required to pay, as soon as practicable, including through additional payroll withholding, any amount of the Withholding Taxes that is not satisfied by the withholding of shares described above.
Leaves of Absence	For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under “Voluntary Termination.” Notwithstanding the foregoing, if the leave of absence exceeds six (6) months, and a return to service upon expiration of such leave is not guaranteed by statute or contract, then you shall be deemed to have had a “separation from service” for purposes of any Restricted Stock Units that are settled hereunder upon such separation. To the extent an authorized leave of absence is due to a medically determinable physical or mental impairment that can be expected to result in death or to last for a continuous period of at least six (6) months and such impairment causes you to be unable to perform the duties of your position of employment or any substantially similar position of employment, the six (6) month period in the prior sentence shall be twenty-nine (29) months.

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

Voting and Other Rights

You shall not have voting rights with respect to the Restricted Stock Units until the date the underlying shares are issued (as evidenced by appropriate entry on the books of PG&E Corporation or its duly authorized transfer agent).

No Retention Rights

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.

Applicable Law

This Agreement will be interpreted and enforced under the laws of the State of California.

**PG&E CORPORATION
2006 LONG-TERM INCENTIVE PLAN**

PERFORMANCE SHARE GRANT

PG&E CORPORATION , a California corporation, hereby grants Performance Shares to the Recipient named below. The Performance Shares have been granted under the PG&E Corporation 2006 Long-Term Incentive Plan, as amended (the "LTIP"). The terms and conditions of the Performance Shares are set forth in this cover sheet and the attached Performance Share Agreement (the "Agreement").

Date of Grant: March 1, 2011

Name of Recipient: _____

Recipient's Participant ID: _____

Number of Performance Shares: _____

By accepting this award, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the Performance Shares dated March 1, 2011.

Attachment

PG&E CORPORATION 2006 LONG-TERM INCENTIVE PLAN

PERFORMANCE SHARE AGREEMENT

The LTIP and Other Agreements

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Performance Shares, subject to the terms of the LTIP. Any prior agreements, commitments or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP. In the event of any conflict between the provisions of this Agreement and the PG&E Corporation Officer Severance Policy, this Agreement shall govern. The LTIP provides the Committee with discretion to adjust the performance award formula.

For purposes of this Agreement, employment with PG&E Corporation shall mean employment with any member of the Participating Company Group.

Grant of Performance Shares

PG&E Corporation grants you the number of Performance Shares shown on the cover sheet of this Agreement. The Performance Shares are subject to the terms and conditions of this Agreement and the LTIP.

Vesting of Performance Shares

As long as you remain employed with PG&E Corporation, the Performance Shares will vest on the first business day of March (the “Vesting Date”) of the third year following the date of grant specified in the cover sheet. Except as described below, all Performance Shares subject to this Agreement that have not vested shall be forfeited upon termination of your employment.

Settlement in Shares

Vested performance shares will be settled in shares of PG&E Corporation common stock, subject to the satisfaction of Withholding Taxes, as described below. The number of shares you are entitled to receive will be calculated by multiplying the number of vested Performance Shares by the “settlement percentage” determined as follows:

Upon the Vesting Date, PG&E Corporation’s total shareholder return (“TSR”) will be compared to the TSR of the twelve other companies in PG&E Corporation’s comparator group ¹ for the prior three calendar years (the “Performance Period”). Subject to rounding considerations, if PG&E Corporation’s TSR falls below the 25th percentile of the comparator group the settlement percentage will be 0%; if PG&E Corporation’s TSR is at the 25th percentile, the settlement percentage will be 25%; if PG&E Corporation’s TSR is at the 75th percentile, the settlement percentage will be 100%; and if PG&E Corporation’s TSR is in the top rank, the settlement percentage will be 200%. The following table sets forth the settlement percentages for the other TSR rankings that could be achieved based on

¹ The current Performance Comparator Group consists of the following companies: American Electric Power, Consolidated Edison, DTE Energy, Duke Energy, NiSource, Inc., Northeast Utilities, Pinnacle West Capital, Progress Energy, Southern Company, SCANA Corp., Wisconsin Energy Corp., and Xcel Energy. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

PG&E Corporation's TSR rank within the comparator group:

**Number of Companies in
Total (Including PG&E Corporation) - 13**

Rank	Performance	Rounded
	Percentile	Payout
1	100%	200%
2	92%	170%
3	83%	130%
4	75%	100%
5	67%	90%
6	58%	75%
7	50%	65%
8	42%	50%
9	33%	35%
10	25%	25%
11	17%	0%
12	8%	0%

The final settlement percentage, if any, will be determined as soon as practicable following the date that the Compensation Committee of the PG&E Corporation Board of Directors certifies the TSR percentile rank over the Performance Period pursuant to Section 10.5(a) of the LTIP. PG&E Corporation will issue shares as soon as practicable after such determination, but no earlier than the Vesting Date, and not later than sixty (60) days after the Vesting Date.

Dividends

Each time that PG&E Corporation declares a dividend on its shares of common stock, an amount equal to the dividend multiplied by the number of Performance Shares granted to you by this Agreement shall be accrued on your behalf. If you receive a Performance Share settlement in accordance with the preceding paragraph, at that same time you also shall receive a cash payment equal to the amount of any dividends accrued with respect to your Performance Shares over the Performance Period multiplied by the same settlement percentage used to determine the number of shares you are entitled to receive, if any.

**Voluntary
Termination**

If you terminate your employment with PG&E Corporation voluntarily before the Vesting Date (other than for Retirement), all of the Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your Performance Shares shall be forfeited.

**Termination for
Cause**

If your employment with PG&E Corporation is terminated at any time by PG&E Corporation for cause before the Vesting Date, all of the Performance Shares shall be cancelled as of the date of such termination and any dividends accrued with respect to your Performance Shares shall be forfeited. In general, termination for "cause" means termination of employment because of dishonesty, a criminal offense or violation of a work rule, and will be determined by and in the sole discretion of PG&E Corporation.

**Termination
other than for
Cause**

If your employment with PG&E Corporation is terminated by PG&E Corporation other than for cause before the Vesting Date, your unvested Performance Shares will vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall be cancelled unless your termination of employment was in connection with a Change in Control as provided below. Your vested Performance Shares will be settled, if at all, as soon as practicable after the Vesting Date based on the same settlement percentage applied to active employees and in any event within sixty (60) days of the Vesting Date. At that time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same settlement percentage used to determine the number of shares you are entitled to receive, if any.

Retirement

If you retire before the Vesting Date, your outstanding Performance Shares will continue to vest as though your employment had continued and will be settled, if at all, as soon as practicable following the Vesting Date and in any event within sixty (60) days of the Vesting Date. At the same time you also shall also receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same settlement percentage used to determine the number of shares you are entitled to receive, if any. You will be considered to have retired if you are age 55 or older on the date of termination and if you were employed by PG&E Corporation for at least five consecutive years ending on the date of termination of your employment.

Death/Disability

If your employment terminates due to your death or disability before the Vesting Date, all of your Performance Shares shall immediately vest and will be settled, if at all, as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date based on the same settlement percentage applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your Performance Shares multiplied by the same settlement percentage used to determine the number of shares you are entitled to receive, if any.

**Termination
Due to
Disposition of
Subsidiary**

If your employment is terminated (other than for cause or your voluntary termination) by reason of a divestiture or change in control of a subsidiary of PG&E Corporation, which divestiture or change in control results in such subsidiary no longer qualifying as a subsidiary corporation under Section 424(f) of the Internal Revenue Code of 1986, as amended, or (2) if your employment is terminated (other than for cause or your voluntary termination) coincident with the sale of all or substantially all of the assets of a subsidiary of PG&E Corporation, all Performance Shares shall vest proportionally based on the number of months during the Performance Period that you were employed (rounded down) divided by the number of months in the Performance Period (36 months). All other outstanding Performance Shares (and any associated accrued dividends) shall automatically be cancelled upon such termination. Your vested Performance Shares will be settled, if at all, as soon as practicable after the Vesting Date

and in any event within sixty (60) days of the Vesting Date, based on the same settlement percentage applied to active employees. At that same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same settlement percentage used to determine the number of shares you are entitled to receive, if any.

Change in Control

In the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the “Acquiror ”), may, without your consent, either assume or continue PG&E Corporation’s rights and obligations under this Agreement or provide a substantially equivalent award in substitution for the Performance Shares subject to this Agreement. If the Acquiror assumes or continues PG&E Corporation’s rights and obligations under this Agreement or substitutes a substantially equivalent award, TSR shall be calculated by aggregating (a) the TSR of PG&E Corporation for the period from January 1 of the year of grant to the date of the Change in Control, and (b) the TSR of the Acquiror from the date of the Change in Control to the last calendar day of the year preceding the Vesting Date. The settlement percentage reflected in the table set forth above for the highest percentile TSR performance met or exceeded when calculated on that basis, and considering any adjustments to the comparator group, will be used to determine the number of shares, if any, you are entitled to receive upon settlement of the assumed, continued or substituted award, which settlement shall occur as soon as practicable after the Vesting Date and in any event within sixty (60) days of the Vesting Date. At that time you also shall receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares over the Performance Period multiplied by the same settlement percentage used to determine the number of shares you are entitled to receive, if any.

If the Change in Control of PG&E Corporation occurs before the original Vesting Date, and if this Award is neither assumed nor continued by the Acquiror or if the Acquiror does not provide a substantially equivalent award in substitution for the Performance Shares subject to this Agreement, all of your outstanding Performance Shares shall automatically vest and become nonforfeitable on the date of the Change in Control. Such vested Performance Shares will be settled, if at all, as soon as practicable following the original Vesting Date and in any event within sixty (60) days of the original Vesting Date. The settlement percentage, if any, will be based on PG&E Corporation’s TSR for the period from January 1 of the year of grant to the date of the Change in Control compared to the TSR of the other companies in PG&E Corporation’s comparator group ² for the same period. At the same time you also shall receive a cash payment, if any, equal to the amount of dividends accrued with respect to your Performance Shares to the date of the Change in Control multiplied by the same settlement percentage used to determine the number of shares you are entitled to receive, if any.

² The current Performance Comparator Group consists of the following companies: American Electric Power, Consolidated Edison, DTE Energy, Duke Energy, NiSource, Inc., Northeast Utilities, Pinnacle West Capital, Progress Energy, Southern Company, SCANA Corp., Wisconsin Energy Corp., and Xcel Energy. PG&E Corporation reserves the right to change the companies comprising the comparator group at any time.

Termination In Connection with a Change in Control

If your employment is terminated by PG&E Corporation other than for cause in connection with a Change in Control within two years following the Change in Control, all of your outstanding Performance Shares (to the extent they did not previously vest upon failure of the Acquiror to assume or continue this Award) shall automatically vest and become nonforfeitable on the date of termination of your employment. If your employment is terminated by PG&E Corporation other than for cause in connection with a change in control within three months before the change in control occurs, all of your outstanding performance shares will automatically vest in full and become nonforfeitable (including the portion that you would have otherwise forfeited based on the proration of vested performance shares through the date of termination of your employment) as of the date of the change in control. Your vested Performance Shares will be settled, if at all, as soon as practicable following the original Vesting Date and in any event within sixty (60) days of the Vesting Date and will be based on the same settlement percentage applied to active employees. You shall also at that time receive a cash payment, if any, equal to the amount of dividends accrued over the Performance Period with respect to your vested Performance Shares multiplied by the same settlement percentage used to determine the number of shares you are entitled to receive, if any. PG&E Corporation shall have the sole discretion to determine whether termination of your employment was made in connection with a Change in Control.

Withholding Taxes

The number of shares of PG&E Corporation common stock that you are otherwise entitled to receive upon settlement of Performance Shares will be reduced by a number of shares having an aggregate Fair Market Value, as determined by PG&E Corporation, equal to the amount of any Federal, state, or local taxes of any kind required by law to be withheld by PG&E Corporation in connection with the Performance Shares determined using the applicable minimum statutory withholding rates, including social security and Medicare taxes due under the Federal Insurance Contributions Act and the California State Disability Insurance tax ("Withholding Taxes"). If the withheld shares were not sufficient to satisfy your minimum Withholding Taxes, you will be required to pay, as soon as practicable, including through additional payroll withholding, any amount of the Withholding Taxes that is not satisfied by the withholding of shares described above.

Leaves of Absence

For purposes of this Agreement, if you are on an approved leave of absence from PG&E Corporation, or a recipient of PG&E Corporation sponsored disability benefits, you will continue to be considered as employed. If you do not return to active employment upon the expiration of your leave of absence or the expiration of your PG&E Corporation sponsored disability benefits, you will be considered to have voluntarily terminated your employment. See above under "Voluntary Termination."

PG&E Corporation reserves the right to determine which leaves of absence will be considered as continuing employment and when your employment terminates for all purposes under this Agreement.

**No Retention
Rights**

This Agreement is not an employment agreement and does not give you the right to be retained by PG&E Corporation. Except as otherwise provided in an applicable employment agreement, PG&E Corporation reserves the right to terminate your employment at any time and for any reason.

Applicable Law

This Agreement will be interpreted and enforced under the laws of the State of California.

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

Three Months

	Ended March 31,	Year Ended December 31,				
	2011	2010	2009	2008	2007	2006
Earnings:						
Net income	\$201	\$1,121	\$1,250	\$1,199	\$1,024	\$985
Income taxes provision	131	574	482	488	571	602
Fixed charges	213	799	817	860	889	801
Total Earnings	\$545	\$2,494	\$2,549	\$2,547	\$2,484	\$2,388
Fixed Charges:						
Interest on short-term borrowings and long-term debt, net	\$199	\$731	\$754	\$794	\$834	\$770
Interest on capital leases	4	18	19	22	23	11
AFUDC debt	10	50	44	44	32	20
Total Fixed Charges	\$213	\$799	\$817	\$860	\$889	\$801
Ratios of Earnings to Fixed Charges	2.56	3.12	3.12	2.96	2.79	2.98

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 income or loss from equity investees 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. Fixed charges exclude interest on tax liabilities.

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

Three Months

	Ended March 31,	Year Ended December 31,				
	2011	2010	2009	2008	2007	2006
Earnings:						
Net income	\$ 201	\$1,121	\$1,250	\$1,199	\$1,024	\$ 985
Income taxes provision	131	574	482	488	571	602
Fixed charges	213	799	817	860	889	801
Total Earnings	\$ 545	\$2,494	\$2,549	\$2,547	\$2,484	\$2,388
Fixed Charges:						
Interest on short-term borrowings and long-term debt, net	\$ 199	\$ 731	\$ 754	\$ 794	\$ 834	\$ 770
Interest on capital leases	4	18	19	22	23	11
AFUDC debt	10	50	44	44	32	20
Total Fixed Charges	\$ 213	\$ 799	\$ 817	\$ 860	\$ 889	\$ 801
Preferred Stock Dividends:						
Tax deductible dividends	2	9	9	9	9	12
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	2	7	7	7	8	3
Total Preferred Stock Dividends	4	16	16	16	17	15
Total Combined Fixed Charges and Preferred Stock Dividends	\$ 217	\$ 815	\$ 833	\$ 876	\$ 906	\$ 816
Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends	2.51	3.06	3.06	2.91	2.74	2.93

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 income or loss from equity investees 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. Fixed charges exclude interest on tax liabilities.

PG&E CORPORATION
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Three Months Ended March 31,		Year Ended December 31,			
	2011	2010	2009	2008	2007	2006
Earnings:						
Income from continuing operations	\$202	\$1,113	\$1,234	\$1,198	\$1,020	\$1,005
Income taxes provision	124	547	460	425	539	554
Fixed charges	223	850	877	907	937	845
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	(4)	(16)	(16)	(16)	(17)	(15)
Total Earnings	\$545	\$2,494	\$2,555	\$2,514	\$2,479	\$2,389
Fixed Charges:						
Interest and amortization of premiums, discounts and capitalized expenses related to short-term borrowings and long-term debt, net	\$205	\$766	\$798	\$825	\$865	\$799
Interest on capital leases	4	18	19	22	23	11
AFUDC debt	10	50	44	44	32	20
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	4	16	16	16	17	15
Total Fixed Charges	\$223	\$850	\$877	\$907	\$937	\$845
Ratios of Earnings to Fixed Charges	2.44	2.93	2.91	2.77	2.65	2.83

Note: For the purpose of computing PG&E Corporation's ratios of earnings to fixed charges, "earnings" represent income from continuing operations adjusted for income taxes, fixed charges (excluding capitalized interest), and pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries. "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 preferred stock dividends of consolidated subsidiaries. Fixed charges exclude interest on tax liabilities.

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

I, C. Lee Cox, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 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: May 4, 2011

C. LEE COX

C. Lee Cox

Interim Chairman, Chief Executive Officer, and President

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

I, Kent M. Harvey, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 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: May 4, 2011

KENT M. HARVEY

Kent M. Harvey

Senior Vice President and Chief Financial Officer

CERTIFICATION OF PRINCIPAL EXECUTIVE 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 March 31, 2011 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: May 4, 2011

CHRISTOPHER P. JOHNS

Christopher P. Johns
President

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

I, Sara A. Cherry, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended March 31, 2011 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: May 4, 2011

SARA A. CHERRY

Sara A. Cherry

Vice President, Finance and Chief Financial Officer

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

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2011 ("Form 10-Q"), I, C. Lee Cox, Interim 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) the Form 10-Q 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 the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

C. LEE COX

C. LEE COX

Interim Chairman, Chief Executive Officer, and
President

May 4, 2011

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

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended March 31, 2011 ("Form 10-Q"), I, Kent M. Harvey, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) the Form 10-Q 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 the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

KENT M. HARVEY
KENT M. HARVEY
Senior Vice President and
Chief Financial Officer

May 4, 2011

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

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2011 ("Form 10-Q"), I, Christopher P. Johns, President 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) the Form 10-Q 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 the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

CHRISTOPHER P. JOHNS

CHRISTOPHER P. JOHNS
President

May 4, 2011

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

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended March 31, 2011 ("Form 10-Q"), I, Sara A. Cherry, Vice President, Finance and Chief Financial 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) the Form 10-Q 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 the Form 10-Q fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

SARA A. CHERRY

SARA A. CHERRY

Vice President, Finance and Chief Financial
Officer

May 4, 2011