

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 September 30, 2010

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 October 25, 2010:

PG&E Corporation
Pacific Gas and Electric Company

392,065,793
264,374,809

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**PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY,
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED SEPTEMBER 30, 2010
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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		Nine Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Operating Revenues				
Electric	\$ 2,857	\$ 2,630	\$ 7,882	\$ 7,610
Natural gas	656	605	2,338	2,250
Total operating revenues	3,513	3,235	10,220	9,860
Operating Expenses				
Cost of electricity	1,102	997	2,885	2,763
Cost of natural gas	182	134	924	879
Operating and maintenance	1,225	1,047	3,175	3,144
Depreciation, amortization, and decommissioning	501	450	1,420	1,298
Total operating expenses	3,010	2,628	8,404	8,084
Operating Income	503	607	1,816	1,776
Interest income	3	1	7	27
Interest expense	(167)	(174)	(510)	(533)
Other income, net	29	23	25	63
Income Before Income Taxes	368	457	1,338	1,333
Income tax provision	107	136	479	376
Net Income	261	321	859	957
Preferred stock dividend requirement of subsidiary	3	3	10	10
Income Available for Common Shareholders	\$ 258	\$ 318	\$ 849	\$ 947
Weighted Average Common Shares Outstanding, Basic	390	370	378	367
Weighted Average Common Shares Outstanding, Diluted	392	388	391	386
Net Earnings Per Common Share, Basic	\$ 0.66	\$ 0.84	\$ 2.22	\$ 2.53
Net Earnings Per Common Share, Diluted	\$ 0.66	\$ 0.83	\$ 2.19	\$ 2.49
Dividends Declared Per Common Share	\$ 0.46	\$ 0.42	\$ 1.37	\$ 1.26

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions)	(Unaudited)	
	Balance At	
	September 30,	December 31,
	2010	2009
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 347	\$ 527
Restricted cash (\$38 and \$39 related to Energy recovery bonds at September 30, 2010 and December 31, 2009, respectively)	573	633
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$76 at September 30, 2010 and \$68 at December 31, 2009)	989	859
Accrued unbilled revenue	752	671
Regulatory balancing accounts	1,118	1,109
Other	786	750
Inventories:		
Gas stored underground and fuel oil	192	114
Materials and supplies	187	200
Income taxes receivable	-	127
Prepaid expenses and other	807	667
Total current assets	5,751	5,657
Property, Plant, and Equipment		
Electric	32,074	30,481
Gas	11,079	10,697
Construction work in progress	2,180	1,888
Other	14	14
Total property, plant, and equipment	45,347	43,080
Accumulated depreciation	(14,672)	(14,188)
Net property, plant, and equipment	30,675	28,892
Other Noncurrent Assets		
Regulatory assets (\$833 and \$1,124 related to Energy recovery bonds at September 30, 2010 and December 31, 2009, respectively)	5,702	5,522
Nuclear decommissioning trusts	1,977	1,899
Income taxes receivable	624	596
Other	524	379
Total other noncurrent assets	8,827	8,396
TOTAL ASSETS	\$ 45,253	\$ 42,945

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
	September 30,	December 31,
(in millions, except share amounts)	2010	2009
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	\$ 1,076	\$ 833
Long-term debt, classified as current	500	342
Energy recovery bonds, classified as current	399	386
Accounts payable:		
Trade creditors	943	984
Disputed claims and customer refunds	746	773
Regulatory balancing accounts	371	281
Other	364	349
Interest payable	787	818
Income taxes payable	260	214
Deferred income taxes	150	332
Other	1,588	1,501
Total current liabilities	7,184	6,813
Noncurrent Liabilities		
Long-term debt	10,727	10,381
Energy recovery bonds	528	827
Regulatory liabilities	4,446	4,125
Pension and other postretirement benefits	2,064	1,773
Asset retirement obligations	1,610	1,593
Deferred income taxes	5,267	4,732
Other	2,152	2,116
Total noncurrent liabilities	26,794	25,547
Commitments and Contingencies		
Equity		
Shareholders' Equity		
Preferred stock, no par value, authorized 80,000,000 shares, \$100 par value, authorized 5,000,000 shares, none issued	-	-
Common stock, no par value, authorized 800,000,000 shares, 391,530,616 shares outstanding (including 475,914 restricted shares) at September 30, 2010 and 371,272,457 shares outstanding (including 670,552 restricted shares) at December 31, 2009	6,712	6,280
Reinvested earnings	4,535	4,213
Accumulated other comprehensive loss	(224)	(160)
Total shareholders' equity	11,023	10,333
Noncontrolling Interest – Preferred Stock of Subsidiary	252	252
Total equity	11,275	10,585
TOTAL LIABILITIES AND EQUITY	\$ 45,253	\$ 42,945

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)	
	Nine Months Ended September 30,	
	2010	2009
Cash Flows from Operating Activities		
Net income	\$ 859	\$ 957
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,609	1,455
Allowance for equity funds used during construction	(89)	(71)
Deferred income taxes and tax credits, net	328	301
Other changes in noncurrent assets and liabilities	(339)	61
Effect of changes in operating assets and liabilities:		
Accounts receivable	(246)	20
Inventories	(65)	78
Accounts payable	17	(159)
Disputed claims and customer refunds	-	(700)
Income taxes receivable/payable	252	658
Regulatory balancing accounts, net	(14)	226
Other current assets	28	27
Other current liabilities	(34)	(50)
Other	14	4
Net cash provided by operating activities	2,320	2,807
Cash Flows from Investing Activities		
Capital expenditures	(2,794)	(3,022)
Decrease in restricted cash	61	732
Proceeds from sales and maturities of nuclear decommissioning trust investments	962	1,177
Purchases of nuclear decommissioning trust investments	(1,001)	(1,219)
Other	(25)	14
Net cash used in investing activities	(2,797)	(2,318)
Cash Flows from Financing Activities		
Borrowings under revolving credit facilities	490	300
Repayments under revolving credit facilities	-	(300)
Net issuance (repayments) of commercial paper, net of discount of \$2 in 2010 and \$3 in 2009	251	(290)
Proceeds from issuance of short-term debt, net of issuance costs of \$1 in 2009	-	499
Proceeds from issuance of long-term debt, net of discount and issuance costs of \$12 in 2010 and \$16 in 2009	838	1,193
Short-term debt matured	(500)	-
Long-term debt matured or repurchased	(95)	(909)
Energy recovery bonds matured	(285)	(273)
Common stock issued	141	211
Common stock dividends paid	(492)	(435)
Other	(51)	(4)
Net cash provided by financing activities	297	(8)
Net change in cash and cash equivalents	(180)	481
Cash and cash equivalents at January 1	527	219
Cash and cash equivalents at September 30	\$ 347	\$ 700
Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	\$ (526)	\$ (493)
Income taxes, net	(52)	437
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	\$ 180	\$ 156
Capital expenditures financed through accounts payable	229	229
Noncash common stock issuances	259	50

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		Nine Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Operating Revenues				
Electric	\$ 2,857	\$ 2,630	\$ 7,882	\$ 7,610
Natural gas	656	605	2,338	2,250
Total operating revenues	3,513	3,235	10,220	9,860
Operating Expenses				
Cost of electricity	1,102	997	2,885	2,763
Cost of natural gas	182	134	924	879
Operating and maintenance	1,224	1,047	3,172	3,143
Depreciation, amortization, and decommissioning	500	450	1,419	1,298
Total operating expenses	3,008	2,628	8,400	8,083
Operating Income	505	607	1,820	1,777
Interest income	3	3	7	29
Interest expense	(161)	(162)	(481)	(501)
Other income, net	25	16	20	52
Income Before Income Taxes	372	464	1,366	1,357
Income tax provision	107	111	498	374
Net Income	265	353	868	983
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	\$ 262	\$ 350	\$ 858	\$ 973

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	
	September 30, 2010	December 31, 2009
ASSETS		
Current Assets		
Cash and cash equivalents	\$ 119	\$ 334
Restricted cash (\$38 and \$39 related to Energy recovery bonds at September 30, 2010 and December 31, 2009, respectively)	573	633
Accounts receivable:		
Customers (net of allowance for doubtful accounts of \$76 at September 30, 2010 and \$68 at December 31, 2009)	989	859
Accrued unbilled revenue	752	671
Regulatory balancing accounts	1,118	1,109
Other	781	751
Inventories:		
Gas stored underground and fuel oil	192	114
Materials and supplies	187	200
Income taxes receivable	-	138
Prepaid expenses and other	806	662
Total current assets	5,517	5,471
Property, Plant, and Equipment		
Electric	32,074	30,481
Gas	11,079	10,697
Construction work in progress	2,180	1,888
Total property, plant, and equipment	45,333	43,066
Accumulated depreciation	(14,659)	(14,175)
Net property, plant, and equipment	30,674	28,891
Other Noncurrent Assets		
Regulatory assets (\$833 and \$1,124 related to Energy recovery bonds at September 30, 2010 and December 31, 2009, respectively)	5,702	5,522
Nuclear decommissioning trusts	1,977	1,899
Income taxes receivable	673	610
Other	357	316
Total other noncurrent assets	8,709	8,347
TOTAL ASSETS	\$ 44,900	\$ 42,709

See accompanying Notes to the Condensed Consolidated Financial Statements.

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**PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS**

	(Unaudited)	
	Balance At	
	September 30,	December 31,
(in millions, except share amounts)	2010	2009
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	\$ 986	\$ 833
Long-term debt, classified as current	500	95
Energy recovery bonds, classified as current	399	386
Accounts payable:		
Trade creditors	943	984
Disputed claims and customer refunds	746	773
Regulatory balancing accounts	371	281
Other	376	363
Interest payable	777	813
Income taxes payable	260	223
Deferred income taxes	154	334
Other	1,377	1,307
Total current liabilities	6,889	6,392
Noncurrent Liabilities		
Long-term debt	10,378	10,033
Energy recovery bonds	528	827
Regulatory liabilities	4,446	4,125
Pension and other postretirement benefits	2,006	1,717
Asset retirement obligations	1,610	1,593
Deferred income taxes	5,322	4,764
Other	2,105	2,073
Total noncurrent liabilities	26,395	25,132
Commitments and Contingencies		
Shareholders' Equity		
Preferred stock without mandatory redemption provisions:		
Nonredeemable, 5.00% to 6.00%, 5,784,825 shares outstanding at September 30, 2010 and December 31, 2009	145	145
Redeemable, 4.36% to 5.00%, 4,534,958 shares outstanding at September 30, 2010 and December 31, 2009	113	113
Common stock, \$5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at September 30, 2010 and December 31, 2009	1,322	1,322
Additional paid-in capital	3,228	3,055
Reinvested earnings	7,025	6,704
Accumulated other comprehensive loss	(217)	(154)
Total shareholders' equity	11,616	11,185
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	\$ 44,900	\$ 42,709

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)	
	Nine Months Ended September 30,	
	2010	2009
Cash Flows from Operating Activities		
Net income	\$ 868	\$ 983
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,580	1,439
Allowance for equity funds used during construction	(89)	(71)
Deferred income taxes and tax credits, net	332	274
Other changes in noncurrent assets and liabilities	(286)	95
Effect of changes in operating assets and liabilities:		
Accounts receivable	(240)	20
Inventories	(65)	78
Accounts payable	15	(151)
Disputed claims and customer refunds	-	(700)
Income taxes receivable/payable	241	534
Regulatory balancing accounts, net	(14)	226
Other current assets	28	26
Other current liabilities	(33)	(62)
Other	14	3
Net cash provided by operating activities	2,351	2,694
Cash Flows from Investing Activities		
Capital expenditures	(2,794)	(3,022)
Decrease in restricted cash	61	732
Proceeds from sales and maturities of nuclear decommissioning trust investments	962	1,177
Purchases of nuclear decommissioning trust investments	(1,001)	(1,219)
Other	15	7
Net cash used in investing activities	(2,757)	(2,325)
Cash Flows from Financing Activities		
Borrowings under revolving credit facilities	400	300
Repayments under revolving credit facilities	-	(300)
Net issuance (repayments) of commercial paper, net of discount of \$2 in 2010 and \$3 in 2009	251	(290)
Proceeds from issuance of short-term debt, net of issuance costs of \$1 in 2009	-	499
Proceeds from issuance of long-term debt, net of discount and issuance costs of \$12 in 2010 and 2009	838	847
Short-term debt matured	(500)	-
Long-term debt matured or repurchased	(95)	(909)
Energy recovery bonds matured	(285)	(273)
Preferred stock dividends paid	(11)	(10)
Common stock dividends paid	(537)	(468)
Equity contribution	170	688
Other	(40)	6
Net cash provided by financing activities	191	90
Net change in cash and cash equivalents	(215)	459
Cash and cash equivalents at January 1	334	52
Cash and cash equivalents at September 30	\$ 119	\$ 511
Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	\$ (504)	\$ (481)
Income taxes, net	(87)	297
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	\$ 229	\$ 229

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 U.S. generally accepted accounting principles (“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 2009 presentation of Cash Flows to present borrowings and repayments on a gross basis rather than a net basis to conform with GAAP. The information at December 31, 2009 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 2009 Annual Report on Form 10-K filed with the SEC on February 19, 2010. PG&E Corporation’s and the Utility’s combined 2009 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 “2009 Annual Report.” This quarterly report should be read in conjunction with the 2009 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, environmental remediation liabilities, asset retirement obligations (“ARO”), income tax-related assets and liabilities, and pension plan and other postretirement plan obligations. In addition, management has made significant estimates and assumptions about accruals related to the rupture of a natural gas transmission pipeline owned and operated by the Utility in the City of San Bruno, California on September 9, 2010, as well as accruals for various legal matters. (See Note 10 below.) Management believes that its estimates and assumptions reflected in the Condensed Consolidated Financial Statements are appropriate and reasonable. A change in management’s estimates or assumptions could result in an adjustment that would have a material impact on PG&E Corporation’s and the Utility’s financial condition and results of operations during the period in which such change occurred.

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 2009 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 and nine-months ended September 30, 2010 and 2009 were as follows:

(in millions)	Pension Benefits		Other Benefits	
	Three Months Ended		Three Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Service cost for benefits earned	\$ 70	\$ 62	\$ 8	\$ 7
Interest cost	162	158	21	23
Expected return on plan assets	(155)	(144)	(18)	(17)
Amortization of transition obligation	-	-	6	6
Amortization of prior service cost	13	16	7	4
Amortization of unrecognized loss	11	27	1	1
Net periodic benefit cost	101	119	25	24
Less: transfer to regulatory account ⁽¹⁾	(60)	(78)	-	-
Total	\$ 41	\$ 41	\$ 25	\$ 24

⁽¹⁾ The Utility recorded \$60 million and \$78 million for the three month periods ended September 30, 2010 and 2009, respectively, to a regulatory account as the amounts are probable of recovery from customers in future rates.

(in millions)	Pension Benefits		Other Benefits	
	Nine Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Service cost for benefits earned	\$ 209	\$ 194	\$ 27	\$ 22
Interest cost	484	468	66	66
Expected return on plan assets	(467)	(434)	(55)	(51)
Amortization of transition obligation	-	-	19	19
Amortization of prior service cost	39	39	19	12
Amortization of unrecognized loss	32	76	2	2
Net periodic benefit cost	297	343	78	70
Less: transfer to regulatory account ⁽¹⁾	(175)	(221)	-	-
Total	\$ 122	\$ 122	\$ 78	\$ 70

⁽¹⁾ The Utility recorded \$175 million and \$221 million for the nine month periods ended September 30, 2010 and 2009, 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 and nine months ended September 30, 2010 and 2009.

On February 16, 2010, the Utility amended its defined benefit medical plans for retirees to provide for additional employer contributions towards retiree premiums. The plan amendment was accounted for as a plan modification that required re-measurement of the accumulated benefit obligation, plan assets, and periodic benefit costs. The inputs and assumptions used in re-measurement did not change significantly from December 31, 2009 and did not have a material impact on the funded status of the plans. The re-measurement of the accumulated benefit obligation and plan assets resulted in an increase to pension and other postretirement benefits and a decrease to other comprehensive income of \$148 million. The impact to net periodic benefit cost was not material.

Adoption of New Accounting Pronouncements***Improvements to Financial Reporting by Enterprises Involved with Variable Interest Entities***

On January 1, 2010, PG&E Corporation and the Utility adopted an accounting standards update that changes when and how to determine, or re-determine, whether an entity is a variable interest entity (“VIE”), which could require consolidation. In addition, the new guidance replaces the quantitative approach for determining who has a controlling financial interest in a VIE with a qualitative approach, and requires ongoing assessments of whether an entity is the primary beneficiary of a VIE. The adoption of the accounting standards update did not have a material impact on PG&E Corporation’s or the Utility’s Condensed Consolidated Financial Statements.

PG&E Corporation and the Utility are required to consolidate any entities which the companies control. In most cases, control can be determined based on majority ownership or voting interests. However, for certain entities, control is difficult to discern based on equity or voting interests alone. These entities are referred to as VIEs. A VIE is an entity which does not have sufficient equity at risk to finance its activities without additional subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise has a controlling financial interest if it has the obligation to absorb expected losses or receive expected gains that could potentially be significant to the VIE and the power to direct the activities that are most significant to the VIE’s economic performance. The enterprise that has a controlling financial interest is known as the VIE’s primary beneficiary and is the enterprise that is required to consolidate the VIE.

Some of the counterparties to the Utility’s power purchase agreements are considered VIEs. In determining whether the Utility has a controlling financial interest in the VIE, the Utility must first assess whether it absorbs any of the VIE’s expected losses or receives portions of the expected residual returns as a result of the power purchase agreement. This assessment includes an evaluation of how the risks and rewards associated with the power plant’s activities are absorbed by variable interest holders. These VIEs are typically exposed to credit risk, production risk, commodity price risk, and any applicable tax incentive risks, among others. The Utility analyzes the variability in the VIE’s gross margin and the impact of the power purchase agreement on the gross margin to determine whether the Utility absorbs variability, resulting in a variable interest. Factors that may be considered when assessing the impact of the power purchase agreement on the VIE’s gross margin include the pricing structure of the agreement and the cost of inputs and production, depending on the technology of the power plant.

For each variable interest, the Utility must also determine whether it has the power to direct the activities of the power plant that most directly impact the VIE’s economic performance. The Utility’s assessment of the activities that are economically significant to the VIE’s performance often include 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 its power purchase agreement with the Utility.

The Utility held a variable interest in several entities that own power plants that generate electricity for sale to the Utility under power purchase agreements. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility utilizing various technologies such as natural gas, wind, solar photovoltaic, solar thermal, hydroelectric, and other technologies. Under each power purchase agreement, the Utility is obligated to purchase electricity or capacity, or both, from the VIEs. The Utility does not provide any other financial or other support to these VIEs and the Utility’s financial exposure is limited to the amount it pays for delivered electricity and capacity. (See Note 10 below.) The Utility does not have the power to direct the activities of the VIE that are most significant to the VIE’s economic performance. As a result, the Utility does not have a controlling financial interest in any of these VIEs. Therefore, at September 30, 2010, the Utility was not the primary beneficiary of any of these VIEs.

The Utility continues to consolidate PG&E Energy Recovery Funding LLC (“PERF”) at September 30, 2010, as the Utility is the primary beneficiary of PERF. The Utility has a controlling financial interest in PERF as the Utility is exposed to PERF’s losses and returns through the Utility’s equity investment in PERF, and the Utility was involved in the design of PERF, an activity that is significant to PERF’s economic performance. The assets of PERF were \$1.0 billion at September 30, 2010, and primarily consisted of assets related to energy recovery bonds, which is included in noncurrent regulatory assets in the Condensed Consolidated Balance Sheets. The liabilities of PERF were \$927 million at September 30, 2010, and consisted of energy recovery bonds, which is 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.

As of September 30, 2010, PG&E Corporation’s affiliates had entered into four tax equity agreements with privately held companies to fund residential and commercial retail solar energy installations. Under these agreements, PG&E Corporation will provide payments of up to \$300 million, and in return, receive the benefits of local rebates, federal investment tax credits, and a share of these entities’ customer payments. As of September 30, 2010, PG&E Corporation had made total payments of \$100 million under these tax equity agreements, which was recorded in noncurrent assets – other in the Condensed Consolidated Balance Sheet. PG&E Corporation holds a variable interest in these entities as a result of these tax equity agreements. When determining whether PG&E

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Corporation was the primary beneficiary of the VIEs, PG&E Corporation evaluated which party had control over significant economic activities such as designing the entities, vendor selection, construction, customer selection, and remarketing activities at the end of the customer leases, among other activities. As these activities were under the control of these VIEs, PG&E Corporation was not the primary beneficiary at September 30, 2010. PG&E Corporation's financial exposure for these arrangements is primarily limited to its lease payments and investment contributions to these entities.

Improving Disclosures about Fair Value Measurements

On January 1, 2010, PG&E Corporation and the Utility adopted an accounting standards update that requires disclosures regarding significant transfers in and out of fair value hierarchy levels, and fair value measurement inputs and valuation techniques. Furthermore, the update requires presentation of disaggregated activity within the reconciliation for fair value measurements using significant unobservable (Level 3) inputs, beginning for the first quarter of 2011. The adoption of the accounting standards update did not have a material impact on PG&E Corporation's or the Utility's Condensed Consolidated Financial Statements.

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 September 30, 2010 and December 31, 2009, the Utility had current regulatory assets of \$641 million and \$427 million, respectively, consisting primarily of the current portion of price risk management regulatory assets. Price risk management regulatory assets represent the deferral of unrealized losses related to price risk management derivative instruments with terms of one year or less. (See Note 7 below for further discussion.) Current regulatory assets are included in prepaid expenses and other in the Condensed Consolidated Balance Sheets.

Long-Term Regulatory Assets

Long-term regulatory assets are composed of the following:

(in millions)	Balance at	
	September 30, 2010	December 31, 2009
Pension benefits	\$ 1,490	\$ 1,386
Deferred income taxes	1,158	1,027
Energy recovery bonds	833	1,124
Utility retained generation	684	737
Price risk management	599	346
Environmental compliance costs	393	408
Unamortized loss, net of gain, on reacquired debt	186	203
Other	359	291
Total long-term regulatory assets	\$ 5,702	\$ 5,522

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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 13 of the Notes to the Consolidated Financial Statements in the 2009 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.

The regulatory asset for energy recovery bonds (“ERBs”) represents the refinancing of the regulatory asset provided for in 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”). (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.

In connection with the 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 14 years.

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 environmental compliance costs represent the portion of estimated environmental remediation costs that the Utility expects to recover in future rates as actual remediation costs are incurred. The Utility expects to recover these costs over the next 32 years. (See Note 10 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 September 30, 2010 and December 31, 2009, “other” primarily consisted of regulatory assets relating to ARO expenses for decommissioning of the Utility’s fossil 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; and costs incurred in relation to the Utility’s plan of reorganization under Chapter 11 that became effective in April 2004. Additionally, at September 30, 2010, “other” included 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 September 30, 2010 and December 31, 2009, the Utility had current regulatory liabilities of \$81 million and \$163 million, respectively, primarily consisting of amounts that the Utility expects to refund to customers for over-collected electric transmission rates; 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; and the current portion of price risk management regulatory liabilities. Price risk management regulatory liabilities represent the deferral of unrealized gains related to price risk management derivative instruments with terms of one year or less. Current regulatory liabilities are included in current liabilities – other in the Condensed Consolidated Balance Sheets.

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Long-Term Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

(in millions)	Balance at	
	September 30, 2010	December 31, 2009
Cost of removal obligation	\$ 3,182	\$ 2,933
Public purpose programs	599	508
Recoveries in excess of ARO	542	488
Other	123	196
Total long-term regulatory liabilities	\$ 4,446	\$ 4,125

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.

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 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 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.

The regulatory liability for recoveries in excess of ARO represents differences between amounts collected in rates for decommissioning the Utility's nuclear power facilities and the ARO expenses recorded in accordance with GAAP. 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.

"Other" at September 30, 2010 and December 31, 2009 primarily consisted of regulatory liabilities related to the deferral of unrealized gains related to price risk management derivative instruments with terms in excess of one year, 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, and insurance recoveries for hazardous substance remediation.

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	
	September 30, 2010	December 31, 2009
Utility generation	\$ 223	\$ 355
Public purpose programs	158	83
Gas fixed cost	134	93
Distribution revenue adjustment mechanism	107	152
Electric transmission	(19)	114
Energy recovery bonds	(93)	(185)
Other	237	216
Total regulatory balancing accounts, net	\$ 747	\$ 828

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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 periods of more temperate weather, there is generally an under-collection in this balancing account due to lower electricity sales and lower rates. During the warmer months of summer, there is generally an over-collection due to higher rates and electric usage that cause an increase in generation revenues.

The public purpose programs balancing accounts primarily 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.

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. The under-collected or over-collected position of this account is dependent on seasonality and volatility in gas volumes.

The electric transmission balancing accounts represent the difference between electric transmission wheeling revenues received by the Utility from the California Independent System Operator ("CAISO") (on behalf of electric transmission customers) and refunds of those revenues to customers, the pass-through of transition access charge and credits for high voltage transmission, reliability service charges, and interest accrued on these account balances. In addition, these balancing accounts include the end-user customer refund balancing account, which is used to refund to customers over-collected electric transmission revenues.

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 September 30, 2010 and December 31, 2009, "other" primarily consisted of the California Department of Water Resources ("DWR") power charge collection balancing account, which ensures amounts collected from customers for DWR-delivered power are remitted to the DWR; balancing accounts that track recovery of the authorized revenue requirements and costs related to the SmartMeter™ advanced metering project; and balancing accounts that track recoverable hazardous substance clean-up costs incurred by the Utility.

NOTE 4: DEBT

PG&E Corporation

Convertible Subordinated Notes

PG&E Corporation issued 16,370,779 shares of common stock upon conversion of the \$247 million principal amount of PG&E Corporation's 9.50% Convertible Subordinated Notes at a conversion price of \$15.09 per share between June 23 and June 29, 2010. These notes were no longer outstanding as of September 30, 2010.

Credit Facilities

At September 30, 2010, PG&E Corporation had \$90 million of cash borrowings outstanding under its \$187 million revolving credit facility which had an average interest rate of 0.59%.

Utility

Senior Notes

On April 1, 2010, the Utility issued \$250 million principal amount of 5.8% Senior Notes due March 1, 2037.

On September 15, 2010, the Utility issued \$550 million principal amount of 3.5% Senior Notes due October 1, 2020.

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On October 12, 2010, the Utility issued \$250 million principal amount of Floating Rate Senior Notes due October 11, 2011. The interest rate for the Floating Rate Senior Notes is equal to the three-month London Interbank Offered Rate ("LIBOR") plus 0.58% and will reset quarterly beginning on January 11, 2011.

Pollution Control Bonds

On April 8, 2010, the California Infrastructure and Economic Development Bank issued \$50 million of tax-exempt pollution control bonds Series 2010E due November 1, 2026 and loaned the proceeds to the Utility. The proceeds were used to refund the corresponding related series of pollution control bonds issued in 2005 which were repurchased by the Utility in 2008. The Series 2010E bonds bear interest at 2.25% per year through April 1, 2012 and are subject to mandatory tender on April 2, 2012 at a price of 100% of the principal amount plus accrued interest. Thereafter, this series of bonds may be remarketed in a fixed or variable rate mode. Interest is payable semi-annually in arrears on April 1 and October 1.

On September 20, 2010, the Utility repurchased \$50 million principal amount of pollution control bonds Series 2008F and \$45 million principal amount of pollution control bonds Series 2008G that were subject to mandatory tender on the same date. The bonds will be remarketed in a fixed or variable rate mode every 30 days until the bonds are reissued. The Utility, as bondholder, will be both the payer and the recipient of principal and interest payments on each remarketing day.

Credit Facilities and Short-Term Borrowings

On June 8, 2010, the Utility entered into a \$750 million unsecured revolving credit agreement with a syndicate of lenders. Of the total credit capacity, \$500 million was used to replace the \$500 million Floating Rate Senior Notes that matured on June 10, 2010. The aggregate facility of \$750 million includes a \$75 million commitment for swingline loans, or loans that are made available on a same-day basis and are repayable in full within 30 days. The Utility can, at any time, repay amounts outstanding in whole or in part. The credit agreement expires on February 26, 2012, unless extended for additional periods at the Utility's request and at the sole discretion of each lender.

Borrowings under the credit agreement (other than swingline loans) will bear interest based, at the Utility's election, on (1) LIBOR plus an applicable margin or (2) the base rate, which will equal the higher of the (i) administrative agent's announced base rate, (ii) 0.5% above the federal funds rate, or (iii) the one-month LIBOR plus an applicable margin. Interest is payable quarterly in arrears, or earlier for loans with shorter interest periods. The Utility also will pay a facility fee on the total commitments of the lenders under the credit agreement. The applicable margin for LIBOR loans and the facility fee will be based on the Utility's senior unsecured, non-credit enhanced debt ratings issued by Standard & Poor's Ratings Services and Moody's Investors Service. Facility fees are payable quarterly in arrears.

The credit agreement contains covenants that are substantially similar to the covenants contained in the Utility's existing \$1.9 billion credit facility, and are usual and customary for credit facilities of this type. Both 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.

At September 30, 2010, the Utility had \$400 million of cash borrowings outstanding under its \$1.9 billion revolving credit facility which had an average interest rate of 0.45%, and no cash borrowings outstanding under its \$750 million revolving credit facility. The \$400 million borrowing was repaid on October 29, 2010.

At September 30, 2010, the Utility had \$289 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 September 30, 2010, the Utility had \$586 million of commercial paper outstanding at an average yield of 0.54%.

Energy Recovery Bonds

In 2005, PERF, a wholly owned consolidated subsidiary of the Utility, 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 \$927 million at September 30, 2010.

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

NOTE 5: EQUITY

PG&E Corporation's and the Utility's changes in equity for the nine months ended September 30, 2010 were as follows:

(in millions)	PG&E Corporation	Utility
	Total Equity	Total Shareholders' Equity
Balance at December 31, 2009	\$ 10,585	\$ 11,185
Net income	859	868
Common stock issued	400	-
Share-based compensation expense	28	-
Common stock dividends declared	(527)	(537)
Preferred stock dividend requirement	-	(10)
Preferred stock dividend requirement of subsidiary	(10)	-
Tax benefit from employee stock plans	4	3
Other comprehensive loss	(64)	(63)
Equity contribution	-	170
Balance at September 30, 2010	\$ 11,275	\$ 11,616

Between June 23 and June 29, 2010, PG&E Corporation issued 16,370,779 shares of common stock upon conversion of the \$247 million principal amount of PG&E Corporation's Convertible Subordinated Notes. In addition, for the nine months ended September 30, 2010, PG&E Corporation issued 3,766,678 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 nine months ended September 30, 2010, PG&E Corporation contributed equity of \$170 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			
	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Net income	\$ 261	\$ 321	\$ 859	\$ 957
Employee benefit plan adjustment, net of tax ⁽¹⁾	8	7	(64)	21
Comprehensive income	\$ 269	\$ 328	\$ 795	\$ 978

⁽¹⁾ These balances are net of income tax expense of \$7 million and \$5 million for the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010, the income tax benefit was \$42 million and for the nine months ended September 30, 2009, the income tax expense was \$14 million.

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(in millions)	Utility			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Net income	\$ 265	\$ 353	\$ 868	\$ 983
Employee benefit plan adjustment, net of tax ⁽¹⁾	9	7	(63)	21
Comprehensive income	\$ 274	\$ 360	\$ 805	\$ 1,004

⁽¹⁾ These balances are net of income tax expense of \$7 million and \$5 million for the three months ended September 30, 2010 and 2009, respectively. For the nine months ended September 30, 2010, the income tax benefit was \$42 million and for the nine months ended September 30, 2009, the income tax expense was \$14 million.

Dividends

PG&E Corporation

During the nine months ended September 30, 2010, PG&E Corporation paid common stock dividends totaling \$492 million, net of \$12 million that was reinvested in additional shares of common stock by participants in the Dividend Reinvestment and Stock Purchase Plan. On September 15, 2010, the Board of Directors of PG&E Corporation declared dividends of \$0.455 per share, totaling \$180 million, which were paid on October 15, 2010 to shareholders on record as of September 30, 2010.

Utility

During the nine months ended September 30, 2010, the Utility paid common stock dividends totaling \$537 million to PG&E Corporation.

During the nine months ended September 30, 2010, the Utility paid dividends totaling \$11 million to holders of its outstanding series of preferred stock. On September 15, 2010, the Board of Directors of the Utility declared dividends totaling \$3 million on its outstanding series of preferred stock, payable on November 15, 2010, to shareholders on record as of October 29, 2010.

NOTE 6: EARNINGS PER SHARE

Earnings per common share ("EPS") is calculated utilizing the "two-class" method, dividing the sum of distributed earnings to common shareholders and undistributed earnings allocated to common shareholders by the weighted average number of common shares outstanding during the period. In applying the two-class method, undistributed earnings are allocated to both common shares and participating securities. PG&E Corporation's Convertible Subordinated Notes met the criteria of participating securities as the holders were entitled to receive pass-through dividends on a 1:1 basis with shares of common stock.

As of September 30, 2010, all of PG&E Corporation's Convertible Subordinated Notes have been converted into common stock. (See Note 4 above for further discussion.)

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 September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Basic				
Income available for common shareholders	\$ 258	\$ 318	\$ 849	\$ 947
Less: distributed earnings to common shareholders	179	156	527	465
Undistributed earnings	\$ 79	\$ 162	\$ 322	\$ 482
Allocation of undistributed earnings to common shareholders				
Distributed earnings to common shareholders	\$ 179	\$ 156	\$ 527	\$ 465
Undistributed earnings allocated to common shareholders	79	155	313	461
Total common shareholders earnings	\$ 258	\$ 311	\$ 840	\$ 926
Weighted average common shares outstanding, basic	390	370	378	367
Convertible subordinated notes	-	16	11	17
Weighted average common shares outstanding and participating securities	390	386	389	384
Net earnings per common share, basic				
Distributed earnings, basic ⁽¹⁾	\$ 0.46	\$ 0.42	\$ 1.39	\$ 1.27
Undistributed earnings, basic	0.20	0.42	0.83	1.26
Total	\$ 0.66	\$ 0.84	\$ 2.22	\$ 2.53

⁽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.

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In calculating diluted EPS, PG&E Corporation applies the “if-converted” method to reflect the dilutive effect of the Convertible Subordinated Notes to the extent that the impact is dilutive when compared to basic EPS. In addition, PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding stock-based compensation in the calculation of diluted EPS.

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 for three and nine months ended September 30, 2010 and 2009:

(in millions, except per share amounts)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Diluted				
Income available for common shareholders	\$ 258	\$ 318	\$ 849	\$ 947
Add earnings impact of assumed conversion of participating securities:				
Interest expense on convertible subordinated notes, net of tax	-	4	8	12
Unrealized loss on embedded derivative, net of tax	-	-	-	2
Income available for common shareholders and assumed conversion	<u>\$ 258</u>	<u>\$ 322</u>	<u>\$ 857</u>	<u>\$ 961</u>
Weighted average common shares outstanding, basic	390	370	378	367
Add incremental shares from assumed conversions:				
Convertible subordinated notes	-	16	11	17
Employee share-based compensation	2	2	2	2
Weighted average common shares outstanding, diluted	<u>392</u>	<u>388</u>	<u>391</u>	<u>386</u>
Total earnings per common share, diluted	<u>\$ 0.66</u>	<u>\$ 0.83</u>	<u>\$ 2.19</u>	<u>\$ 2.49</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 faces market risk primarily related to electricity and natural gas commodity prices. All of the Utility’s risk management activities involving derivatives occur to reduce the volatility of commodity costs on behalf of its customers. The CPUC and the FERC allow 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. As these costs are passed through to customers in rates, the Utility’s earnings are not exposed to the commodity price risk inherent in the purchase and sale of 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;

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- option contracts that provide the Utility with the right to buy a commodity at a predetermined price; and
- futures contracts that are exchange-traded contracts committing the Utility to make a cash settlement at a specified price and future date.

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

Commodity-Related Price Risk

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.

The following is a discussion of the Utility's use of derivative instruments intended to mitigate commodity-related price risk for its customers.

Electricity Procurement

The Utility obtains electricity from a diverse mix of resources, including third-party power purchase agreements, amounts allocated under DWR contracts, and its own electricity generation facilities. The amount of electricity the Utility needs to meet the demands of customers and that is not satisfied from the Utility's own generation facilities, existing purchase contracts, or DWR contracts allocated to the Utility's 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;
- fluctuation in the output of hydroelectric and other renewable power facilities owned or under contract;
- changes in the Utility's customers' electricity demands due to customer and economic growth 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; and
- changes in market prices that make it more economical to purchase power in the market rather than use the Utility's existing resources.

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.

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Electric Transmission Congestion Revenue Rights

The 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 CRRs held by the Utility are considered derivative instruments.

Natural Gas Procurement (Electric 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 futures, 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 (Small Commercial and Residential Customers)

The Utility enters into physical natural gas commodity contracts to fulfill the needs of its small commercial and residential, or “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 markets 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.

Volume of Derivative Activity

At September 30, 2010, the volume 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,				
	Futures, and	393,102,663	266,868,040	8,970,000	-
	Swaps				
	Options	218,112,080	172,925,000	10,800,000	-
Electricity (Megawatt-hours)	Forwards,				
	Futures, and	5,242,021	7,664,859	4,060,087	4,974,816
	Swaps				
	Options	1,211,030	-	239,028	421,464
	Congestion Revenue Rights	53,171,874	69,986,929	67,512,934	93,842,817

⁽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 2015 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.

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At September 30, 2010, PG&E Corporation's and the Utility's outstanding derivative balances were as follows:

(in millions)	Gross Derivative Balance ⁽¹⁾	Netting ⁽²⁾	Cash Collateral ⁽²⁾	Total Derivative Balances
Commodity Risk (PG&E Corporation and Utility)				
Current assets – prepaid expenses and other	\$ 19	\$ (11)	\$ 52	\$ 60
Other noncurrent assets – other	59	(42)	64	81
Current liabilities – other	(411)	11	177	(223)
Noncurrent liabilities – other	(641)	42	239	(360)
Total commodity risk	\$ (974)	\$ -	\$ 532	\$ (442)

⁽¹⁾ See Note 8 below for a discussion of the valuation techniques used to calculate the fair value of these instruments.

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

At December 31, 2009, 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 Utility)				
Current assets – prepaid expenses and other	\$ 76	\$ (12)	\$ 77	\$ 141
Other noncurrent assets – other	64	(44)	13	33
Current liabilities – other	(231)	12	54	(165)
Noncurrent liabilities – other	(390)	44	44	(302)
Total commodity risk	\$ (481)	\$ -	\$ 188	\$ (293)
Other Risk Instruments ⁽²⁾ (PG&E Corporation Only)				
Current liabilities – other	\$ (13)	\$ -	\$ -	\$ (13)
Total derivatives	\$ (494)	\$ -	\$ 188	\$ (306)

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

⁽²⁾ This category relates to the dividend participation rights of PG&E Corporation's Convertible Subordinated Notes, which were fully converted as of September 30, 2010.

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 September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Unrealized gain/(loss) - regulatory assets and liabilities ⁽¹⁾	\$ (222)	\$ 192	\$ (493)	\$ 32
Realized gain/(loss) - cost of electricity ⁽²⁾	(154)	(133)	(435)	(558)
Realized gain/(loss) - cost of natural gas ⁽²⁾	(6)	(1)	(50)	(30)
Total commodity risk instruments	\$ (382)	\$ 58	\$ (978)	\$ (556)

⁽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 recognized in operating cash flows on PG&E Corporation's and the Utility's Condensed Consolidated Statements of Cash Flows.

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The majority of the Utility's commodity risk-related derivative instruments contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. 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.

At September 30, 2010, the additional cash collateral the Utility would be required to post if its credit risk-related contingent features were triggered was as follows:

(in millions)	
Derivatives in a liability position with credit-risk-related contingencies that are not fully collateralized	\$ (652)
Related derivatives in an asset position	1
Collateral posting in the normal course of business related to these derivatives	74
Net position of derivative contracts/additional collateral posting requirements ⁽¹⁾	\$ (577)

⁽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 —Include 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.

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):

Fair Value Measurements at September 30, 2010				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Money market investments	\$ 227	\$ -	\$ -	\$ 227
Nuclear decommissioning trusts				
U.S. equity securities ⁽¹⁾	796	6	-	802
Non-U.S. equity securities	328	-	-	328
U.S. government and agency securities	757	48	-	805
Municipal securities	-	107	-	107
Other fixed income securities	-	80	-	80
Total nuclear decommissioning trusts ⁽²⁾	1,881	241	-	2,122
Price risk management instruments				
Electric ⁽³⁾	83	-	-	83
Total price risk management instruments	83	-	-	83
Rabbi trusts				
Equity securities	23	-	-	23
Life insurance contracts	-	65	-	65
Total rabbi trusts	23	65	-	88
Long-term disability trust				
U.S. equity securities ⁽¹⁾	7	23	-	30
Corporate debt securities ⁽¹⁾	-	132	-	132
Total long-term disability trust	7	155	-	162
Total assets	\$ 2,221	\$ 461	\$ -	\$ 2,682
Liabilities:				

Price risk management instruments				
Electric ⁽⁴⁾	\$ -	\$ 30	\$ 436	\$ 466
Gas ⁽⁵⁾	-	2	57	59
Total price risk management instruments	-	32	493	525
Total liabilities	\$ -	\$ 32	\$ 493	\$ 525

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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 deferred taxes on appreciation of investment value.

(3) Balances include the impact of netting adjustments of \$365 million to Level 1. Includes natural gas for electric portfolio.

(4) Balances include the impact of netting adjustments of \$62 million to Level 2 and \$52 million to Level 3. Includes natural gas for electric portfolio.

(5) Balances include the impact of netting adjustments of \$53 million to Level 3. Includes natural gas for core customers.

Fair Value Measurements at December 31, 2009				
(in millions)	Level 1	Level 2	Level 3	Total
Assets:				
Money market investments	\$ 189	\$ -	\$ 4	\$ 193
Nuclear decommissioning trusts				
U.S. equity securities ⁽¹⁾	762	6	-	768
Non-U.S. equity securities	344	-	-	344
U.S. government and agency securities	653	51	-	704
Municipal securities	1	89	-	90
Other fixed income securities	-	108	-	108
Total nuclear decommissioning trusts ⁽²⁾	1,760	254	-	2,014
Rabbi trusts				
Equity securities	21	-	-	21
Life insurance contracts	60	-	-	60
Total rabbi trusts	81	-	-	81
Long-term disability trust				
U.S. equity securities ⁽¹⁾	52	23	-	75
Corporate debt securities ⁽¹⁾	-	113	-	113
Total long-term disability trust	52	136	-	188
Total assets	\$ 2,082	\$ 390	\$ 4	\$ 2,476
Liabilities:				
Dividend participation rights ⁽³⁾	\$ -	\$ -	\$ 12	\$ 12
Price risk management instruments				
Electric ⁽⁴⁾	2	73	157	232
Gas ⁽⁵⁾	1	-	60	61
Total price risk management instruments	3	73	217	293
Other liabilities	-	-	3	3
Total liabilities	\$ 3	\$ 73	\$ 232	\$ 308

(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 deferred taxes on appreciation of investment value.

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(3) The dividend participation rights were associated with PG&E Corporation's Convertible Subordinated Notes which were no longer outstanding as of September 30, 2010.

(4) Balances include the impact of netting adjustments of \$108 million to Level 1, \$48 million to Level 2, and \$19 million to Level 3. Includes natural gas for electric portfolio.

(5) Balances include the impact of netting adjustments of \$13 million to Level 3. Includes natural gas for core customers.

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. Equity securities primarily include investments in common stock and commingled funds comprised of equity 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 or unadjusted prices in active markets for similar transactions. Debt securities are comprised primarily of fixed income securities that include U.S. government and agency securities, municipal securities, and corporate debt securities. A market based valuation approach is generally used to estimate the fair value of debt securities classified as Level 2 instruments in the tables above. 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. No trust assets were measured at fair value using significant unobservable inputs (Level 3) at September 30, 2010.

Price Risk Management Instruments

Price risk management instruments include physical and financial derivative contracts, such as futures, forwards, swaps, options, and CRRs that are either exchange-traded or over-the-counter traded. Some futures, forwards, and swaps are valued using observable market prices for the underlying commodity or an identical instrument and are classified as Level 1 or Level 2 instruments. Other instruments are valued using unobservable inputs and are considered Level 3 instruments.

Certain exchange-traded contracts are classified as Level 2 measurements because the contract term extends to a period at which the market is no longer considered active; however, the prices are still observable. This determination is based on an analysis of the relevant characteristics of the market such as trading hours and volumes, frequency of available quotes, and open interest. In addition, a number of over-the-counter contracts are valued using unadjusted exchange prices of similar instruments in active markets. Such instruments are classified as Level 2 measurements as they are not exchange-traded instruments.

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. Some of these assumptions are derived from internal models as they are unobservable. The Utility's demand response contracts with third-party aggregators of retail electricity customers contain a call option entitling the Utility to require that the aggregator reduce electric usage by the aggregator's customers at times of peak energy demand or in response to a CAISO alert or other emergency.

The Utility holds CRRs to hedge financial risk of CAISO-imposed congestion charges in the day-ahead markets. CRRs are valued based on the forecasted settlement price at the delivery points underlying the CRR using internal models. The Utility also uses the most current annual auction prices published by the CAISO to calibrate internal models. Limited market data is available between auction dates; therefore, CRRs are classified as Level 3 measurements.

The Utility enters into power purchase agreements for the purchase of electricity to meet the demand of its customers. (See Note 7 above.) The Utility uses internal models to determine the fair value of these power purchase agreements. These power purchase agreements include contract terms that extend beyond a period for which an active market exists. The Utility utilizes market data for the underlying commodity to the extent that it is available in determining the fair value. For periods where market data is not available, the Utility extrapolates forward prices based on historical data. These power purchase agreements are considered Level 3 instruments as the determination of their fair value includes the use of unobservable forward prices.

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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 nine month period ended September 30, 2010. The following tables present reconciliations for assets and liabilities measured and recorded at fair value on a recurring basis, using significant unobservable inputs (Level 3), for the three and nine month periods ended September 30, 2010 and 2009:

	PG&E Corporation Only		PG&E Corporation and the Utility					
		Dividend Participation	Price Risk Management	Nuclear Decommissioning Trusts Equity Securities ⁽¹⁾	Long- Term Disability Equity Securities	Long-Term Disability Corp. Debt Securities	Other Liabilities	Total
(in millions)	Money Market	Rights	Instruments					
Asset (liability) balance as of June 30, 2010	\$ -	\$ -	\$ (400)	\$ -	\$ -	\$ -	\$ (2)	\$ (402)
Realized and unrealized gains (losses):								
Included in earnings	-	-	-	-	-	-	-	-
Included in regulatory assets and liabilities or balancing accounts	-	-	(93)	-	-	-	2	(91)
Purchases, issuances, and settlements	-	-	-	-	-	-	-	-
Transfers into Level 3	-	-	-	-	-	-	-	-
Transfers out of Level 3	-	-	-	-	-	-	-	-
Asset (liability) balance as of September 30, 2010	\$ -	\$ -	\$ (493)	\$ -	\$ -	\$ -	\$ -	\$ (493)

⁽¹⁾ Excludes deferred taxes on appreciation of investment value.

	PG&E Corporation Only		PG&E Corporation and the Utility					
		Dividend Participation	Price Risk Management	Nuclear Decommissioning Trusts Equity Securities ⁽¹⁾	Long- Term Disability Equity Securities	Long-Term Disability Corp. Debt Securities	Other Liabilities	Total
(in millions)	Money Market	Rights	Instruments					
Asset (liability) balance as of June 30, 2009	\$ 5	\$ (27)	\$ (189)	\$ 5	\$ 57	\$ 24	\$ (3)	\$ (128)
Realized and unrealized gains (losses):								
Included in earnings	-	-	-	-	8	2	-	10
Included in regulatory assets and liabilities or balancing accounts	-	-	32	1	-	-	(1)	32
Purchases, issuances, and settlements	-	7	-	-	(45)	75	-	37
Transfers into Level 3	-	-	-	-	-	-	-	-
Transfers out of Level 3	-	-	-	-	-	-	-	-
Asset (liability) balance as of September 30, 2009	\$ 5	\$ (20)	\$ (157)	\$ 6	\$ 20	\$ 101	\$ (4)	\$ (49)

⁽¹⁾ Excludes deferred taxes on appreciation of investment value.

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	PG&E Corporation Only			PG&E Corporation and the Utility				
		Dividend Participation	Price Risk Management	Nuclear Decommissioning	Long-Term Disability	Long-Term Disability		
(in millions)	Money Market	Rights	Instruments	Trusts Equity Securities ⁽¹⁾	Equity Securities	Corp. Debt Securities	Other Liabilities	Total
Asset (liability) balance as of December 31, 2009	\$ 4	\$ (12)	\$ (217)	\$ -	\$ -	\$ -	\$ (3)	\$ (228)
Realized and unrealized gains (losses):								
Included in earnings	-	-	-	-	-	-	-	-
Included in regulatory assets and liabilities or balancing accounts	-	-	(276)	-	-	-	3	(273)
Purchases, issuances, and settlements	(4)	12	-	-	-	-	-	8
Transfers into Level 3	-	-	-	-	-	-	-	-
Transfers out of Level 3	-	-	-	-	-	-	-	-
Asset (liability) balance as of September 30, 2010	\$ -	\$ -	\$ (493)	\$ -	\$ -	\$ -	\$ -	\$ (493)

⁽¹⁾ Excludes deferred taxes on appreciation of investment value.

	PG&E Corporation Only			PG&E Corporation and the Utility				
		Dividend Participation	Price Risk Management	Nuclear Decommissioning	Long-Term Disability	Long-Term Disability		
(in millions)	Money Market	Rights	Instruments	Trusts Equity Securities ⁽¹⁾	Equity Securities	Corp. Debt Securities	Other Liabilities	Total
Asset (liability) balance as of December 31, 2008	\$ 12	\$ (42)	\$ (156)	\$ 5	\$ 54	\$ 24	\$ (2)	\$ (105)
Realized and unrealized gains (losses):								
Included in earnings	-	1	-	-	11	3	-	15
Included in regulatory assets and liabilities or balancing accounts	-	-	(1)	1	-	-	(2)	(2)
Purchases, issuances, and settlements	(7)	21	-	-	(45)	74	-	43
Transfers into Level 3	-	-	-	-	-	-	-	-
Transfers out of Level 3	-	-	-	-	-	-	-	-
Asset (liability) balance as of September 30, 2009	\$ 5	\$ (20)	\$ (157)	\$ 6	\$ 20	\$ 101	\$ (4)	\$ (49)

Excludes deferred taxes on appreciation of investment value.

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Financial Instruments

The Utility values its long-term debt using quoted market prices that are readily available. The carrying amount and fair value of PG&E Corporation's and the Utility's financial instruments were as follows (the table below excludes financial instruments with carrying values that approximate their fair values):

(in millions)	At September 30, 2010		At December 31, 2009	
	Carrying		Carrying	
	Amount	Fair Value ⁽²⁾	Amount	Fair Value ⁽²⁾
Debt (Note 4):				
PG&E Corporation ⁽¹⁾	\$ 349	\$ 394	\$ 597	\$ 1,096
Utility	9,956	11,226	9,240	9,824
Energy recovery bonds (Note 4)	927	973	1,213	1,269

⁽¹⁾ PG&E Corporation Convertible Subordinated Notes were no longer outstanding as of September 30, 2010.

⁽²⁾ Fair values are determined using readily available quoted market prices.

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 summarizes unrealized gains and losses related to available-for-sale investments held in the Utility's nuclear decommissioning trusts:

(in millions)	Amortized	Total	Total	Estimated
	Cost	Unrealized	Unrealized	⁽¹⁾ Fair Value
As of September 30, 2010				
U.S. equity securities	\$ 359	\$ 446	\$ (3)	\$ 802
Non-U.S. equity securities	178	151	(1)	328
U.S. government and agency securities	710	95	-	805
Municipal securities	104	4	(1)	107
Other fixed income securities	77	3	-	80
Total	\$ 1,428	\$ 699	\$ (5)	\$ 2,122
As of December 31, 2009				
U.S. equity securities	\$ 344	\$ 425	\$ (1)	\$ 768
Non-U.S. equity securities	182	163	(1)	344
U.S. government and agency securities	656	52	(4)	704
Municipal securities	89	1	-	90
Other fixed income securities	108	2	(2)	108
Total	\$ 1,379	\$ 643	\$ (8)	\$ 2,014

⁽¹⁾ Excludes taxes on appreciation of investment value.

The following table summarizes the estimated fair value of debt securities classified by the contractual maturity date of the security:

	<u>At September 30,</u> <u>2010</u>
(in millions)	
Less than 1 year	\$ 64
1–5 years	447
5–10 years	238
More than 10 years	242
Total maturities of debt securities	<u>\$ 991</u>

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The following table provides a summary of activity for available-for-sale securities:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
(in millions)				
Proceeds received from sales of securities	\$ 277	\$ 223	\$ 962	\$ 1,177
Gross realized gains on sales of securities held as available-for-sale	4	12	26	24
Gross realized losses on sales of securities held as available-for-sale	(2)	(2)	(8)	(52)

In general, investments held in the nuclear decommissioning trusts are exposed to various risks, such as interest rate, credit, and market volatility risks. It is reasonably possible that changes in the market values of investment securities could occur in the near term, and such changes could materially affect the trusts' fair value.

NOTE 9: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

Various electricity suppliers filed claims in the Utility's proceeding under Chapter 11 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 September 30, 2010 and December 31, 2009, the Utility held \$512 million and \$515 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 disputed claims liability and interest accrued from December 31, 2009 to September 30, 2010:

(in millions)	
Balance at December 31, 2009	\$ 946
Interest accrued	23
Less: supplier settlements	(41)
Balance at September 30, 2010	\$ 928

At September 30, 2010, the Utility's net disputed claims liability was \$928 million, consisting of \$746 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 \$676 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 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.

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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.

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 September 30, 2010, the undiscounted future expected power purchase agreement payments were as follows:

(in millions)	
2010	\$ 600
2011	2,424
2012	2,483
2013	2,958
2014	3,188
Thereafter	54,375
Total	\$ 66,028

Payments made by the Utility under power purchase agreements amounted to \$1,791 million and \$1,809 million for the nine months ended September 30, 2010 and September 30, 2009, respectively. The amounts above do not include payments related to the DWR purchases for the benefit of the Utility's customers, as the Utility only acts as an agent for the DWR.

Some of the power purchase agreements that the Utility entered into with independent power producers that are qualifying facilities ("QF"s) are treated as capital leases. The following table shows the future fixed capacity payments due under the QF contracts that are treated as capital leases. (These amounts are also included in the table above.) The fixed capacity payments are discounted to their present value using the Utility's incremental borrowing rate at the inception of the leases. The amount of this discount is shown as the amount representing interest.

(in millions)	
2010	\$ 11
2011	50
2012	50
2013	50
2014	42
Thereafter	162
Total fixed capacity payments	365
Amount representing interest	77
Present value of fixed capacity payments	\$ 288

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 Utility's recognition of the lease expense conforms to the ratemaking treatment for the Utility's recovery of the cost of electricity. The QF contracts that are treated as capital leases expire between April 2014 and September 2021.

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At September 30, 2010 and December 31, 2009, PG&E Corporation and the Utility had, respectively, \$33 million and \$32 million included in current liabilities – other, and \$255 million and \$282 million included in noncurrent liabilities – other, respectively representing the present value of the fixed capacity payments due under these contracts recorded on PG&E Corporation’s and the Utility’s Condensed Consolidated Balance Sheets. The corresponding assets at September 30, 2010 and December 31, 2009 of \$288 million and \$314 million, including amortization of \$120 million and \$94 million, respectively, are included in property, plant, and equipment on PG&E Corporation’s and the Utility’s Condensed Consolidated Balance Sheets.

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. The contract lengths and natural gas sources of the Utility’s portfolio of natural gas procurement contracts can fluctuate based on market conditions. The Utility also contracts for natural gas transportation to transport natural gas from the points at which the Utility takes delivery (typically in Canada and the southwestern United States supply basins) to the points at which the Utility’s natural gas transportation system begins. In addition, the Utility has contracted for gas storage services in its market area in order to better meet winter peak customer loads.

The Utility also purchases natural gas to fuel its owned-generation facilities. Contract terms typically range in length from one to three years.

At September 30, 2010, the Utility’s undiscounted obligations for natural gas purchases, gas transportation services, and gas storage were as follows:

(in millions)	
2010	\$ 301
2011	550
2012	84
2013	68
2014	49
Thereafter	115
Total ⁽¹⁾	\$ 1,167

⁽¹⁾ Total does not include Ruby Pipeline reservation cost commitment described below.

Payments for natural gas purchases, gas transportation services, and gas storage amounted to \$1,183 million and \$959 million for the nine months ended September 30, 2010 and September 30, 2009, respectively.

Ruby Pipeline

On April 5, 2010, the FERC issued an order authorizing El Paso Corporation to construct, operate, and maintain its proposed 675-mile gas transmission pipeline (“Ruby Pipeline”), which would begin at the Opal Hub in Wyoming and terminate at the Malin, Oregon, interconnect, near California’s northern border and have an initial capacity of 1.5 billion cubic feet per day. Construction began in July 2010, and the facilities are scheduled to be in service in the spring of 2011. The Utility has contracted for firm service rights on the Ruby Pipeline of approximately 0.4 billion cubic feet per day beginning in 2011. Under these agreements the Utility will have a cumulative commitment of \$1.4 billion over 15 years.

Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements have terms ranging from 1 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 2014, while contracts for fuel fabrication services provide for 100% coverage of reactor requirements through 2011. 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.

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At September 30, 2010, the undiscounted obligations under nuclear fuel agreements were as follows:

(in millions)	
2010	\$ 15
2011	82
2012	69
2013	107
2014	135
Thereafter	1,215
Total	\$ 1,623

Payments for nuclear fuel amounted to \$140 million and \$67 million for the nine months ended September 30, 2010 and September 30, 2009, respectively.

Contingencies

PG&E Corporation

PG&E Corporation retains a guarantee related to certain obligations of its former subsidiary, National Energy & 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.

Utility

Energy Efficiency Programs and Incentive Ratemaking

The CPUC has established a ratemaking mechanism to provide incentives to the California investor-owned utilities to meet the CPUC's energy savings goals through implementation of the utilities' 2006-2008 energy efficiency programs. In accordance with this mechanism, the CPUC has awarded the Utility interim incentive revenues totaling \$75 million through December 31, 2009 based on the energy savings achieved through implementation of the Utility's energy efficiency programs during the 2006 through 2008 program cycle. The amount of additional incentive revenues the Utility may earn, if any, is subject to the CPUC's completion of the final true-up process.

On September 28, 2010, a proposed decision was issued by the assigned CPUC administrative law judge recommending that no additional incentive revenues be awarded to the Utility. Also, on September 28, 2010, an alternate proposed decision was issued by a CPUC commissioner recommending that the Utility be awarded additional incentive revenues of \$40 million, an amount equal to the amounts that had been held back from the interim awards.

The CPUC is scheduled to issue a final decision to complete the true-up process by the end of 2010. PG&E Corporation and the Utility are unable to predict the amount, if any, of additional incentive revenues that the Utility will receive 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 Power Plant ("Diablo Canyon") and its retired nuclear facility at Humboldt Bay.

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, 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 is still pending in the U.S. Court of Appeals for the Ninth Circuit. The appellants claim that the NRC failed to adequately consider environmental impacts of a potential terrorist attack at Diablo Canyon. The Ninth Circuit has set November 4, 2010 as the date for oral argument.

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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 Utility incurred at least \$188 million between 2005 and 2009 to build on-site storage facilities. 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 to build on-site storage facilities between 2005 and 2009. 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 \$40 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 an 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.

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.

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 (the “San Bruno Accident”). The ensuing explosion and fire resulted in the deaths of eight people and injuries to numerous individuals. At least thirty-four houses were destroyed and many additional houses were damaged. The cause of the rupture remains unknown. The California Governor’s office declared a state of emergency in San Mateo County, where San Bruno is located, to mobilize state emergency services and resources.

On September 10, 2010, the National Transportation Safety Board (“NTSB”) began an investigation of the San Bruno Accident. In addition to reviewing the physical evidence collected from the site and conducting further metallurgical tests, the NTSB is expected to examine, among other aspects, the performance, qualifications and experience of the relevant employees; and the emergency preparedness and response of the Utility and of public emergency personnel and other first responders. While the NTSB investigation is pending the Utility generally is prohibited from disclosing information related to the investigation without approval from the NTSB.

On September 12, 2010, the Utility announced that it would provide up to \$100 million to assist affected residents and the City of San Bruno, California, to pay for (1) affected residents’ immediate expenses not otherwise covered by insurance, including temporary living expenses, insurance deductibles and immediate medical expenses; (2) property replacement, repair or purchase (in the case of homes destroyed or substantially damaged) and (3) work needed to rebuild or replace public property damaged or destroyed in the San Bruno Accident, as well as costs incurred by emergency responders and government services to respond to the fire. These payments are not intended to satisfy any potential claims for personal injury or wrongful death, which will be addressed separately.

On October 13, 2010, the NTSB released a preliminary report. The report included a timeline of events before and after the gas line rupture, but did not identify the cause of the rupture. The NTSB also identified which tests had been performed on the section of ruptured pipeline and which tests were yet to be completed. The NTSB stated that additional factual updates will be provided and distributed via media advisory as investigative information is developed.

The CPUC also has initiated an investigation 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 has appointed an independent review panel to gather facts, review these 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. These recommendations may include changes to design, construction, operation and maintenance of natural gas facilities, management practices at the Utility in the areas of pipeline integrity and public safety, regulatory and statutory changes, and other recommendations deemed appropriate, including whether there are systemic management problems at the Utility and whether greater resources are needed to achieve fundamental infrastructure improvement. The Utility is committed to working with the NTSB, the CPUC, and the independent panel to determine the cause of the rupture.

Various lawsuits, including two class action lawsuits, have been filed by residents of San Bruno in California state courts against PG&E Corporation and the Utility. The class action lawsuits allege causes of action for strict liability, negligence, public nuisance, private nuisance, and declaratory relief, including a demand that the \$100 million the Utility announced would be available for assistance (discussed above) be placed under court supervision. In addition, some of these lawsuits seek recovery for wrongful death, property damage, and personal injury. Several other residents also have submitted damage claims to the Utility.

As of September 30, 2010, the Utility has recorded a provision of \$220 million for estimated third-party claims related to the San Bruno Accident, including personal injury and property damage claims, damage to infrastructure, emergency response, and other damage claims. The provision is included in operating and maintenance expense in PG&E Corporation’s and the Utility’s Condensed Consolidated Statements of Income, and other current liabilities in PG&E Corporation’s and the Utility’s Condensed Consolidated Balance Sheets for the period ended September 30, 2010. The Utility estimates that it may incur as much as \$400 million for third-party claims depending on the final outcome of the NTSB and CPUC investigations and the number, nature, and value of third-party claims. This range of estimates incorporates up to \$100 million that the Utility has stated it would provide the affected residents and the City of San Bruno. The process for estimating costs associated with third-party claims relating to the San Bruno Accident requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including information resulting from the NTSB and CPUC investigations, management’s estimates and assumptions regarding the financial impact of the San Bruno Accident may change.

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 most 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 September 30, 2010. PG&E Corporation and the Utility are unable to predict the amount and timing of insurance recoveries.

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Other Legal Matters

The accrued liability for legal matters (other than those related to the San Bruno Accident as discussed above) is included in PG&E Corporation's and the Utility's current liabilities – other in the Condensed Consolidated Balance Sheets and totaled \$46 million at September 30, 2010 and \$57 million at December 31, 2009. PG&E Corporation and the Utility are not able to predict the ultimate outcome of these various legal matters, but after consideration of these accruals, PG&E Corporation and the Utility do not believe that losses associated with these matters would have a material adverse impact on their financial condition or results of operations.

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 gross environmental remediation liability of \$608 million at September 30, 2010 and \$586 million at December 31, 2009. The following table presents the changes in the environmental remediation liability from December 31, 2009:

(in millions)	
Balance at December 31, 2009	\$ 586
Additional remediation costs accrued:	
Transfer to regulatory account for recovery	86
Amounts not recoverable from customers	21
Less: Payments	(85)
Balance at September 30, 2010	<u>\$ 608</u>

The \$608 million accrued at September 30, 2010 consists of the following:

- \$41 million for remediation at the Utility's natural gas compressor site located near Hinkley, California;
- \$173 million for remediation at the Utility's natural gas compressor site located on the California border, near Topock, Arizona;
- \$87 million related to remediation at divested generation facilities;
- \$116 million related to remediation costs for the Utility's generation and other facilities and for third-party disposal sites;
- \$141 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
- \$50 million related to remediation decommissioning fossil-fueled sites.

The Utility has a program, in cooperation with the California Environmental Protection Agency, to evaluate and take appropriate action to mitigate any potential environmental concerns posed by certain former MGPs located throughout the Utility's service territory. Of the forty one MGP sites owned or operated by the Utility, forty have been or are in the process of being investigated and/or remediated, and the Utility is developing a strategy to investigate and remediate the last site.

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Of the \$608 million environmental remediation liability, the Utility expects to recover \$323 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 \$121 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. 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 \$1.1 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.

Tax Matters

PG&E Corporation and the Utility receive a federal subsidy for maintaining a retiree medical benefit plan with prescription drug benefits that is actuarially equivalent to Medicare Part D. For federal income tax purposes, the subsidy was deductible when contributed to the benefit plan maintained for these benefits. On March 30, 2010, federal healthcare legislation was signed eliminating the deduction for subsidy contributions after 2012. As a result, PG&E Corporation and the Utility recognized an expense of \$20 million in the first quarter of 2010 to reverse previously recognized federal tax benefits (recorded as an increase to income tax provision and a reduction to deferred income tax assets for subsidy amounts included in the calculation of accrued retiree medical benefit obligation).

On September 29, 2010, PG&E Corporation received the Internal Revenue Service ("IRS") examination report for the 2005 to 2007 audit years and resolved substantially all matters except for several items that will be discussed with the IRS Appeals office. Included in the 2005 to 2007 audit was the resolution of the change in accounting method related to the capitalization of indirect service costs for those years. As a result, PG&E Corporation recorded a \$25 million reduction to income tax expense in the third quarter of 2010.

For tax years 2008 through 2010, PG&E Corporation participates in the Compliance Assurance Process ("CAP"), a real-time IRS audit intended to expedite matter resolution. 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.

On August 24, 2010, the IRS accepted PG&E Corporation's 2009 tax return. The IRS has ninety days to conduct a post-filing review to ensure that the final return properly reflects the positions agreed upon.

The California Franchise Tax Board 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. It is uncertain when the Franchise Tax Board will complete the California 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.

As of September 30, 2010, PG&E Corporation has \$24 million of federal and California capital loss carry forwards based on filed tax returns, of which approximately \$9 million will expire if not used by December 31, 2011. For all periods presented, PG&E Corporation has provided a full valuation allowance against its deferred income tax assets for capital loss carry forwards.

For a discussion of unrecognized tax benefits, see Note 9 of the Notes to the Consolidated Financial Statements in the 2009 Annual Report. PG&E Corporation and the Utility believe there are no positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease within 12 months of the reporting date.

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 September 30, 2010. The Utility had \$44.9 billion in assets at September 30, 2010 and generated revenues of \$10.2 billion in the nine months ended September 30, 2010.

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, 2009 which incorporates by reference each company's audited Consolidated Financial Statements, the Notes to the Consolidated Financial Statements, and other information incorporated by reference ("2009 Annual Report").

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 (the "San Bruno Accident"). The ensuing explosion and fire resulted in the deaths of eight people and injuries to numerous individuals. At least thirty-four houses were destroyed and many additional houses were damaged. The cause of the rupture remains unknown. The California Governor's office declared a state of emergency in San Mateo County, where San Bruno is located, to mobilize state emergency services and resources.

On September 10, 2010, the National Transportation Safety Board ("NTSB") began an investigation of the San Bruno Accident. In addition to reviewing the physical evidence collected from the site and conducting further metallurgical tests, the NTSB is expected to examine, among other aspects, the performance, qualifications and experience of the relevant employees, and the emergency preparedness and response of the Utility and of public emergency personnel and other first responders. While the NTSB investigation is pending the Utility generally is prohibited from disclosing information related to the investigation without approval from the NTSB.

On September 12, 2010, the Utility announced that it would provide up to \$100 million to assist affected residents and the City of San Bruno, California, to pay for (1) affected residents' immediate expenses not otherwise covered by insurance, including temporary living expenses, insurance deductibles, and immediate medical expenses; (2) property replacement, repair or purchase (in the case of homes destroyed or substantially damaged) and (3) work needed to rebuild or replace public property damaged or destroyed in the San Bruno Accident, as well as costs incurred by emergency responders and government services to respond to the fire. These payments are not intended to satisfy any potential claims for personal injury or wrongful death, which will be addressed separately.

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On October 13, 2010, the NTSB released a preliminary report. The report included a timeline of events before and after the gas line rupture, but did not identify the cause of the rupture. The NTSB also identified which tests had been performed on the section of ruptured pipeline and which tests were yet to be completed. The NTSB stated that additional factual updates will be provided and distributed via media advisory as investigative information is developed.

The CPUC also has initiated an investigation 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 has appointed an independent review panel to gather facts, review these 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. These recommendations may include changes to design, construction, operation and maintenance of natural gas facilities, management practices at the Utility in the areas of pipeline integrity and public safety, regulatory and statutory changes, and other recommendations deemed appropriate, including whether there are systemic management problems at the Utility and whether greater resources are needed to achieve fundamental infrastructure improvement. The Utility is committed to working with the NTSB, the CPUC, and the independent panel to determine the cause of the rupture.

Various lawsuits, including two class action lawsuits, have been filed by residents of San Bruno in California state courts against PG&E Corporation and the Utility. (See Part II, Item 1. Legal Proceedings, below.) Several other residents also have submitted damage claims to the Utility. In addition, on October 4, 2010, PG&E Corporation received a letter on behalf of a purported shareholder 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 letter requests a response within 60 days, i.e., by December 3, 2010. PG&E Corporation intends to respond before December 3, 2010. A purported shareholder derivative action also has been filed 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.

As of September 30, 2010, the Utility has recorded a provision of \$220 million for estimated third-party claims related to the San Bruno Accident, including personal injury and property damage claims, damage to infrastructure, emergency response, and other damage claims. The provision is included in operating and maintenance expense in PG&E Corporation's and the Utility's Condensed Consolidated Statements of Income, and other current liabilities in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets for the period ended September 30, 2010. The Utility estimates that it may incur as much as \$400 million for third-party claims depending on the final outcome of the NTSB and CPUC investigations and the number, nature, and value of third-party claims. This range of estimates incorporates up to \$100 million that the Utility has stated it would provide the affected residents and the City of San Bruno. The process for estimating costs associated with third-party claims relating to the San Bruno Accident requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including information resulting from the NTSB and CPUC investigations, management's estimates and assumptions regarding the financial impact of the San Bruno Accident may change.

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 most 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 September 30, 2010. PG&E Corporation and the Utility are unable to predict the amount and timing of insurance recoveries.

Other significant developments that have occurred since the 2009 Annual Report was filed with the Securities and Exchange Commission on February 19, 2010 are discussed in this Quarterly Report on Form 10-Q.

Summary of Changes in Earnings per Common Share and Income Available for Common Shareholders for the Three and Nine Months Ended September 30, 2010

PG&E Corporation's diluted earnings per common share ("EPS") for the three months ended September 30, 2010 was \$0.66 compared to \$0.83 for the same period in 2009. For the nine months ended September 30, 2010, PG&E Corporation's diluted EPS was \$2.19 compared to \$2.49 for the same period in 2009. PG&E Corporation's income available for common shareholders for the three months ended September 30, 2010 decreased by \$60 million, or 19%, to \$258 million, compared to \$318 million for the same period in 2009. For the nine months ended September 30, 2010, income available for common shareholders decreased by \$98 million, or 10%, to \$849 million, compared to \$947 million for the same period in 2009. The primary factors associated with these decreases are discussed below.

Income available for common shareholders decreased for both the three and nine months ended September 30, 2010, as compared to the same periods in 2009, primarily due to costs of \$141 million, after tax, related to the San Bruno Accident.

For the three months ended September 30, 2010, the costs related to the San Bruno Accident were partially offset by \$26 million that the Utility earned on higher authorized capital investments as compared to the same period in 2009. In addition, net income was higher as compared to the same period in 2009 when the Utility incurred \$30 million of employee severance costs and \$16 million of costs to perform accelerated gas leak surveys. These comparative increases also helped to offset the costs related to the San Bruno Accident.

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For the nine months ended September 30, 2010, the decrease in income available for common shareholders also was driven by (1) \$45 million, after tax, of costs the Utility incurred to support a June 2010 ballot initiative and (2) a \$19 million, after tax, charge triggered by the elimination of the tax deductibility of the Medicare Part D federal subsidy. These negative factors were partially offset by (1) an increase of \$65 million, after tax, that the Utility earned on higher authorized capital investments compared to the same period in 2009 and (2) higher net income of \$32 million, after tax, compared to the same period in 2009 when the Utility incurred costs in connection with a scheduled refueling outage at Diablo Canyon.

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 Regulatory Proceedings*. There are several rate cases that are currently pending at the CPUC and the FERC, the outcome of which will determine the majority of the Utility's base revenue requirements for 2011 and several years thereafter. In the 2011 General Rate Case ("2011 GRC"), the CPUC will authorize the Utility's revenue requirements for its electric and natural gas distribution operations and its electric generation operations from 2011 through 2013. The CPUC will also authorize the Utility's revenue requirements for its natural gas transportation and storage services from 2011 through 2014 in the pending gas transmission and storage rate case. In addition, on July 28, 2010, the Utility filed its 13th Electric Transmission Owner ("TO") rate case requesting the FERC to determine the amount of electric transmission revenues the Utility can recover beginning in March 2011. (See "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. (See "Capital Expenditures" below.) The outcome of these regulatory proceedings can be affected by many factors, including general economic conditions, the level of customer rates, and political and regulatory policies.
- *The Ability of the Utility to Control Costs*. 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, as well as to earn a return on equity ("ROE") and recover depreciation, tax, and interest expenses associated with forecasted capital expenditures. Actual costs may differ from forecasts, or the Utility may incur significant unanticipated costs related to storms, outages, catastrophic events, or to comply with regulatory orders or legislation. Although the Utility continuously reprioritizes its capital and expense spending to meet customer needs and maintain and improve operational safety and reliability, the Utility may be unable to offset unanticipated costs. 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. (See "Capital Expenditures" below.)
- *Authorized Capital Structure, Rate of Return, and Financing*. The CPUC has authorized a capital structure for the Utility's electric and natural gas distribution and electric generation rate base that consists of 52% common equity and 48% debt and preferred stock. This authorized capital structure will remain in effect through 2012. The CPUC also has authorized the Utility to earn a rate of return on each component of its capital structure, including a ROE of 11.35%. These rates will remain in effect through 2011. The rates for 2012 are subject to an annual adjustment mechanism that will be triggered if the 12-month October-through-September average yield for the applicable Moody's Investors Service utility bond index increases or decreases by more than 1% as compared to the applicable benchmark. The amount of the Utility's authorized equity earnings is determined by the 52% equity component, the 11.35% ROE, and the aggregate amount of rate base authorized by the CPUC. The rate of return that the Utility earns on its FERC-jurisdictional rate base is not specifically authorized, but rates are designed to allow the Utility to earn a reasonable rate of return. The CPUC periodically 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 timing and amount of the Utility's future financing will depend on various factors, as discussed in "Liquidity and Financial Resources" below. PG&E Corporation contributes equity to the Utility as needed by the Utility to maintain its CPUC-authorized capital structure. PG&E Corporation may issue debt or equity in the future to fund these equity contributions.

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 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 or legislative 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, and whether the utility is required to incur costs to comply with regulatory or legislative mandates that it is unable to recover through rates or insurance;
- the adequacy and price of electricity and natural gas supplies and whether the new day-ahead, hour-ahead, and real-time wholesale electricity markets established by the California Independent System Operator will continue to function effectively, 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, 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 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 the Utility's application to renew the operating licenses for Diablo Canyon, and potential changes in laws or regulations promulgated by the NRC or environmental agencies with respect to the storage of spent nuclear fuel, security, safety, 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 implement its program to install advanced meters for its electric and natural gas customers and integrate the new meters with its customer billing and other systems, the outcome of the independent investigation ordered by the CPUC and the California Legislature into customer concerns about the new meters, and the ability of the Utility to implement various rate changes including "dynamic pricing" by offering electric rates that can vary with the customer's time of use and are more closely aligned with wholesale electricity prices;

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- 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, including those arising from the San Bruno Accident, that are not recoverable through insurance, rates, or from other third parties;
- 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 and the costs of compliance and remediation;
- 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.

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 discussion in the section entitled "Risk Factors" in the 2009 Annual Report and Item 1A. in Part II 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 and nine months ended September 30, 2010 and 2009:

(in millions)	Three Months Ended September 30,		Nine Months Ended September 30,	
	2010	2009	2010	2009
Utility				
Electric operating revenues	\$ 2,857	\$ 2,630	\$ 7,882	\$ 7,610
Natural gas operating revenues	656	605	2,338	2,250
Total operating revenues	3,513	3,235	10,220	9,860
Cost of electricity	1,102	997	2,885	2,763
Cost of natural gas	182	134	924	879
Operating and maintenance	1,224	1,047	3,172	3,143
Depreciation, amortization, and decommissioning	500	450	1,419	1,298
Total operating expenses	3,008	2,628	8,400	8,083
Operating Income	505	607	1,820	1,777
Interest income	3	3	7	29
Interest expense	(161)	(162)	(481)	(501)
Other income, net	25	16	20	52
Income Before Income Taxes	372	464	1,366	1,357
Income tax provision	107	111	498	374
Net Income	265	353	868	983
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	\$ 262	\$ 350	\$ 858	\$ 973
PG&E Corporation, Eliminations, and Other ⁽¹⁾				
Operating revenues	\$ -	\$ -	\$ -	\$ -
Operating expenses	2	-	4	1
Operating Loss	(2)	-	(4)	(1)
Interest income	-	(2)	-	(2)
Interest expense	(6)	(12)	(29)	(32)
Other income, net	4	7	5	11
Loss Before Income Taxes	(4)	(7)	(28)	(24)
Income tax provision (benefit)	-	25	(19)	2
Net Loss	\$ (4)	\$ (32)	\$ (9)	\$ (26)
Consolidated Total				
Operating revenues	\$ 3,513	\$ 3,235	\$ 10,220	\$ 9,860
Operating expenses	3,010	2,628	8,404	8,084
Operating Income	503	607	1,816	1,776
Interest income	3	1	7	27
Interest expense	(167)	(174)	(510)	(533)
Other income, net	29	23	25	63
Income Before Income Taxes	368	457	1,338	1,333
Income tax provision	107	136	479	376
Net Income	261	321	859	957
Preferred stock dividend requirement of subsidiary	3	3	10	10
Income Available for Common Shareholders	\$ 258	\$ 318	\$ 849	\$ 947

⁽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 and nine months ended September 30, 2010 and 2009.

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, and 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' demand for electricity ("load") is satisfied by electricity provided under long-term contracts between the California Department of Water Resources ("DWR") and various power suppliers.

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

(in millions)	Three Months Ended		Nine Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Electric revenues	\$ 3,245	\$ 3,233	\$ 8,930	\$ 9,066
DWR pass-through revenues ⁽¹⁾	(388)	(603)	(1,048)	(1,456)
Total electric operating revenues	\$ 2,857	\$ 2,630	\$ 7,882	\$ 7,610

⁽¹⁾ These are revenues collected on behalf of the DWR for electricity allocated to the Utility's customers under contracts between the DWR and power suppliers, and are not included in the Utility's Condensed Consolidated Statements of Income.

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, increased by \$227 million, or 9%, in the three months ended September 30, 2010, as compared to the same period in 2009. Costs that are passed through to customers and do not impact net income increased by \$145 million, primarily due to an increase in the cost of public purpose programs, higher costs of electric procurement, and the return of collateral from counterparties in 2009. (See "Cost of Electricity" below.) Electric operating revenues, excluding costs passed through to customers, increased by \$82 million. This was primarily due to an increase in authorized base revenues of \$60 million.

The Utility's total electric operating revenues, including revenues intended to recover costs that are passed through to customers, increased by \$272 million, or 4% in the nine months ended September 30, 2010, as compared to the same period in 2009. Costs that are passed through to customers and do not impact net income increased by \$124 million, primarily due to an increase in the cost of public purpose programs and higher costs of electric procurement. (See "Cost of Electricity" below.) Electric operating revenues, excluding costs passed through to customers, increased by \$148 million. This was primarily due to an increase in authorized base revenues of \$163 million, which was partially offset by a decrease in revenues of \$35 million, representing the amount the Utility received in April 2009 to recover costs it had previously incurred in connection with its hydroelectric generation facilities.

The Utility's future electric operating revenues will depend on the amount of revenue requirements authorized by the FERC and the CPUC in various regulatory proceedings. The Utility also expects to continue to collect revenue requirements to recover capital expenditures related to specific projects approved by the CPUC. (See "Capital Expenditures" below.) Finally, the CPUC has not yet determined how the existing energy efficiency incentive mechanism will be modified, so the amount of incentive revenues the Utility may earn for the implementation of its programs in 2009 and future years is uncertain. (See "Regulatory Matters" below.)

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 generation facilities, and the cost of fuel supplied to other facilities under tolling agreements. The Utility's cost of electricity also includes 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 the Utility's own generation facilities, which are included in operating and maintenance expense in the Condensed Consolidated Statements of Income. The cost of electricity provided to the Utility customers under power purchase agreements between the DWR and various power suppliers is also excluded from the Utility's cost of electricity.

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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		Nine Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Cost of purchased power	\$ 1,041	\$ 947	\$ 2,694	\$ 2,620
Fuel used in own generation	61	50	191	143
Total cost of electricity	\$ 1,102	\$ 997	\$ 2,885	\$ 2,763
Average cost of purchased power per kWh ⁽¹⁾	\$ 0.082	\$ 0.076	\$ 0.083	\$ 0.081
Total purchased power (in kWh)	12,742	12,524	32,568	32,238

⁽¹⁾ Kilowatt-hour

The Utility's total cost of electricity increased by \$105 million, or 11%, and \$122 million, or 4%, in the three and nine months ended September 30, 2010, respectively, as compared to the same periods in 2009. This was caused by an increase in the price of purchased power and an increase in the cost of fuel used in the Utility's own generation facilities as the Utility increased its non-nuclear generation to replace power that had previously been provided under a DWR contract that expired at the end of 2009 (costs associated with power provided to the Utility's customers under DWR contracts are not included in the Utility's cost of purchased power). The Utility's mix of resources is determined by 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 level of hydroelectric and nuclear power produced by the Utility, the cost of procuring more renewable energy, changes in customer demand, and the amount and timing of power purchases needed to replace power previously supplied under the DWR contracts as those contracts expire or are terminated, novated, or renegotiated.

The Utility's future cost of electricity may also be affected by federal or state legislation or rules that may be adopted to regulate the emissions of greenhouse gases ("GHG") from the Utility's electricity generating facilities or other generating facilities from which the Utility procures electricity. In particular, costs are likely to increase in the future when the California Global Warming Solutions Act of 2006 ("AB 32") is implemented. (See "Environmental Matters" below.)

Natural Gas Operating Revenues

The Utility sells natural gas, natural gas transportation services, and natural gas storage services. The Utility's transportation services are provided by a transmission system and a distribution system. The transmission system transports gas throughout its service territory for delivery to the Utility's distribution system, which, in turn, delivers natural gas to end-use customers. The transmission system also delivers natural gas 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		Nine Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Bundled natural gas revenues	\$ 568	\$ 525	\$ 2,062	\$ 2,003
Transportation service-only revenues	88	80	276	247
Total natural gas operating revenues	\$ 656	\$ 605	\$ 2,338	\$ 2,250

The Utility's total natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, increased by \$51 million, or 8%, in the three months ended September 30, 2010 as compared to the same period in 2009. This reflects a \$48 million increase in the total cost of natural gas due to higher market prices which is passed through to customers and does not impact net income. (See "Cost of Natural Gas" below.) Natural gas operating revenues, excluding items passed through to customers, increased by \$3 million. This was primarily due to a \$16 million increase in authorized base revenues, partially offset by an \$8 million decrease as compared to the same period in 2009 when the Utility received a shareholder incentive award based on its core portfolio gas procurement.

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The Utility's total natural gas operating revenues, including revenues intended to recover costs that are passed through to customers, increased by \$88 million, or 4%, in the nine months ended September 30, 2010 as compared to the same period in 2009. This reflects a \$45 million increase in the total cost of natural gas due to higher market prices and a \$16 million increase in the cost of public purpose programs, which are passed through to customers and do not impact net income. Natural gas operating revenues, excluding items passed through to customers, increased by \$27 million. This was primarily due to a \$39 million increase in authorized base revenues, partially offset by an \$8 million decrease as compared to the same period in 2009 when the Utility received a shareholder incentive award based on its core portfolio gas procurement.

The Utility's future natural gas operating revenues will depend on the amount of revenue requirements authorized by the CPUC in various regulatory proceedings. (See "Regulatory Matters" below.) Additionally, the Utility's future natural gas operating revenues will be impacted by the cost of natural gas. The Utility also expects future natural gas operating revenues to increase to the extent that the CPUC approves the Utility's separately funded capital projects. The CPUC has not yet determined how the existing energy efficiency incentive mechanism will be modified, so the amount of incentive revenues that the Utility may earn for the implementation of its programs in 2009 and future years is uncertain. (See "Regulatory Matters" below.)

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		Nine Months Ended	
	September 30,		September 30,	
	2010	2009	2010	2009
Cost of natural gas sold	\$ 142	\$ 96	\$ 796	\$ 760
Transportation cost of natural gas sold	40	38	128	119
Total cost of natural gas	\$ 182	\$ 134	\$ 924	\$ 879
Average cost per Mcf ⁽¹⁾ of natural gas sold	\$ 4.18	\$ 2.91	\$ 4.54	\$ 4.09
Total natural gas sold (in Mcf)	34	33	186	186

⁽¹⁾ One thousand cubic feet.

The Utility's total cost of natural gas increased by \$48 million, or 36%, and \$45 million, or 5%, in the three and nine months ended September 30, 2010, respectively, as compared to the same periods in 2009, primarily due to higher market prices for natural gas, which are passed through to customers and do not impact net income. The increase in the nine months ended September 30, 2010 was partially offset by 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 1999-2002.

The Utility's future cost of natural gas will be affected by the market price of natural gas and changes in customer demand. The Utility's future cost of gas may also 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 increased by \$177 million, or 17%, in the three months ended September 30, 2010, as compared to the same period in 2009, primarily due to \$238 million of costs associated with the San Bruno Accident. This amount includes a provision of \$220 million for estimated third-party claims. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.) This increase was partially offset by a \$51 million decrease in severance costs as compared to the same period in 2009 when charges were incurred related to the reduction of approximately 2% of the Utility's workforce, and by a \$27 million decrease in labor and other costs as compared to the same period in 2009 when the Utility performed accelerated natural gas leak surveys and associated remedial work.

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The Utility's operating and maintenance expenses increased by \$29 million, or 1%, in the nine months ended September 30, 2010, compared to the same period in 2009, primarily due to \$238 million of costs associated with the San Bruno Accident, partially offset by decreases of \$105 million in labor costs and other costs as compared to 2009 when costs were incurred in connection with the scheduled refueling outage at Diablo Canyon and accelerated natural gas leak surveys and associated remedial work, and \$69 million in severance costs as compared to the same period in 2009 when charges were incurred related to the reduction of approximately 2% of the Utility's workforce. Additionally, operating and maintenance expenses decreased as a result of a \$35 million decrease in other miscellaneous operating and maintenance expenses, including costs associated with uncollectible customer accounts and pass through costs associated with the new day-ahead market.

The Utility estimates it may incur a material amount of additional expenses related to the San Bruno Accident through 2011. In addition, the Utility may incur costs in response to recommendations that may be made by the NTSB and the CPUC in the course of their investigations of the San Bruno Accident and possible federal and/or state legislative mandates. Depending on the outcome of the NTSB and CPUC investigations and other factors, the Utility may also incur additional provisions for third-party claims related to the San Bruno Accident. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.) The Utility also may incur costs to comply with CPUC orders or recommendations that may be made as the CPUC conducts the "safety phase" of the Utility's 2011 Gas Transmission and Storage Rate Case. (See "Regulatory Matters" below.) Finally, the Utility may incur higher expenses in future periods to obtain or renew permits and to operate and maintain its aging electric and natural gas infrastructure.

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 \$50 million, or 11%, in the three months ended September 30, 2010, and \$121 million, or 9%, in the nine months ended September 30, 2010, as compared to the same periods in 2009. These changes are primarily due to an increase in capital additions.

The Utility's depreciation expense for future periods is expected to increase as a result of an overall increase in net capital additions. Additionally, depreciation expense in subsequent years will be impacted by the depreciation rates set by the CPUC in the 2011 GRC and the 2011 gas transmission and storage rate case, and by the FERC in future TO rate cases.

Interest Income

The Utility's interest income decreased by less than \$1 million, or less than 1%, in the three months ended September 30, 2010 as compared to the same period in 2009. Interest income decreased by \$22 million, or 76% in the nine months ended September 30, 2010, as compared to the same period in 2009, when the Utility recovered \$12 million of interest costs related to the proposed divestiture of its hydroelectric generation facilities (with no similar activity in the current year).

The Utility's interest income in future periods primarily will be 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.

Interest Expense

The Utility's interest expense decreased by \$1 million, or less than 1%, and \$20 million, or 4% in the three and nine months ended September 30, 2010, respectively, as compared to the same periods in 2009. This decrease was primarily attributable to lower interest rates on outstanding short-term debt and decreases in the outstanding balances of the liability for Chapter 11 disputed claims and various regulatory balancing accounts and regulatory assets. This decrease was partially offset by interest that accrued on higher outstanding balances of long-term debt due to the timing of senior note issuances. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements for further discussion.)

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.

Other Income, Net

The Utility's other income net increased by \$9 million, or 56%, in the three months ended September 30, 2010, as compared to the same periods in 2009. The increase in the three months ended September 30, 2010 was primarily due to an increase in allowance for equity funds used during construction due to higher average balances of construction work in progress.

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The Utility's other income net decreased by \$32 million, or 62%, in the nine months ended September 30, 2010, as compared to the same period in 2009. The decrease in the nine months ended September 30, 2010 was primarily due to an increase in other expenses as a result of costs the Utility incurred to support the Taxpayers' Right to Vote Act, a California ballot initiative that appeared on the June 2010 ballot. These costs are not recovered in rates.

Income Tax Provision

The Utility's income tax provision decreased by \$4 million, or 4%, for the three months ended September 30, 2010, as compared to the same period in 2009. The effective tax rates for the three months ended September 30, 2010 and 2009 were 29% and 24%, respectively. The effective tax rate for the three months ended September 30, 2010 increased as compared to the same period in 2009 when the Utility recognized (1) state tax benefits arising from accounting method changes and (2) the benefits of various audit settlements at higher levels than 2010 settlements.

The Utility's income tax provision increased by \$124 million, or 33% for the nine months ended September 30, 2010, as compared to the same period in 2009. The effective tax rates for the nine months ended September 30, 2010 and 2009 were 37% and 28%, respectively. The effective tax rate for the nine months ended September 30, 2010 increased as compared to the same period in 2009 when the Utility (1) recognized state tax benefits arising from accounting method changes, (2) recognized the benefits of various audit settlements at higher levels than 2010 settlements, and (3) received a federal tax refund. The effective tax rate also increased due to the reversal of a deferred tax asset in the first quarter of 2010 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 March 2010. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements for a discussion of "Tax Matters.")

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 Convertible Subordinated Notes and 5.8% Senior Notes, and is not allocated to affiliates.

There were no material changes to PG&E Corporation's operating income in the three and nine months ended September 30, 2010, as compared to the same periods in 2009.

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 markets. The levels of the Utility's operating cash and short-term debt fluctuate as a result of seasonal demand for electricity 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 Utility has short-term borrowing authority of \$4.0 billion, including \$500 million that is restricted for use in 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 capital 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 markets.

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Credit Facilities

The following table summarizes PG&E Corporation's and the Utility's outstanding commercial paper and revolving credit facilities at September 30, 2010:

(in millions)	Termination Date	Letters of Credit		Cash Borrowings	Commercial Paper Backup	Availability
		Facility Limit	Outstanding			
PG&E Corporation	February 2012	\$ 187 ⁽¹⁾	\$ -	\$ 90	N/A	\$ 97
Utility	February 2012	1,940 ⁽²⁾	289	400	\$ 586	665
Utility	February 2012	750 ⁽³⁾	N/A	-	-	750
Total credit facilities		\$ 2,877	\$ 289	\$ 490	\$ 586	\$ 1,512

⁽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.

In the nine months ended September 30, 2010, the average outstanding commercial paper balance was \$745 million. There were no borrowings outstanding under the \$1.9 billion revolving credit facilities until September 29, 2010, at which time \$400 million was borrowed to pay down the then outstanding commercial paper balance. The \$400 million borrowing was repaid on October 29, 2010.

On June 8, 2010, the Utility entered into a \$750 million unsecured revolving credit agreement with a syndicate of lenders. The Utility will use \$500 million of the credit capacity under the credit agreement to support its electric procurement hedging activities. This credit capacity replaced the \$500 million Floating Rate Senior Notes that matured on June 10, 2010. The remaining credit capacity of \$250 million will be used for general working capital purposes. The credit agreement contains 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 \$1.9 billion 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 September 30, 2010, PG&E Corporation and the Utility were in compliance with all covenants under each of the revolving credit facilities listed in the table above.

2010 Financings

On April 1, 2010, the Utility issued \$250 million principal amount of 5.8% Senior Notes due March 1, 2037. The proceeds from this issuance were used to repay a portion of outstanding commercial paper.

On April 8, 2010, the California Infrastructure and Economic Development Bank issued \$50 million of tax-exempt pollution control bonds series 2010E due November 1, 2026 and loaned the proceeds to the Utility. The proceeds were used to refund the corresponding related series of pollution control bonds issued in 2005 which were repurchased by the Utility in 2008. The series 2010E bonds bear interest at 2.25% per year through April 1, 2012 and are subject to mandatory tender on April 2, 2012 at a price of 100% of the principal amount plus accrued interest. Thereafter, this series of bonds may be remarketed in a fixed or variable rate mode. Interest is payable semi-annually in arrears on April 1 and October 1.

On September 15, 2010, the Utility issued \$550 million of 3.5% Senior Notes due October 1, 2020. The proceeds from this issuance were used to repay a portion of outstanding commercial paper.

On September 20, 2010, the Utility repurchased \$50 million principal amount of pollution control bonds series 2008F and \$45 million principal amount of pollution control bonds series 2008G that were subject to mandatory tender on the same date. The bonds will be remarketed in a fixed or variable rate mode every 30 days until the bonds are reissued. The Utility, as bondholder, will be both the payer and the recipient of principal and interest payments on each remarketing day.

On October 12, 2010, the Utility issued \$250 million principal amount of Floating Rate Senior Notes due October 11, 2011. The net proceeds were used to repay outstanding commercial paper that was issued to satisfy margin calls and collateral requirements related to the Utility's electric procurement commodity hedging activities.

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PG&E Corporation issued 3,766,678 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 \$141 million of cash during the nine months ended September 30, 2010. PG&E Corporation issued 16,370,779 shares of common stock upon conversion of the \$247 million principal amount of PG&E Corporation's Convertible Subordinated Notes at a conversion price of \$15.09 per share between June 23 and June 29, 2010. These notes were no longer outstanding at September 30, 2010, and the conversion had no impact on cash.

PG&E Corporation also contributed \$170 million of cash to the Utility during the nine months ended September 30, 2010 to ensure that the Utility had adequate capital to fund its capital expenditures and to maintain the 52% common equity ratio authorized by the CPUC.

Future Financing Needs

The amount and timing of the Utility's future financing needs will depend on various factors, including the timing and amount of forecasted capital expenditures, the amount of cash internally generated through normal business operations, 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 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 may issue debt or equity in the future to fund equity contributions to the Utility and to fund investments to the extent that internally generated funds are not sufficient. As of September 30, 2010, PG&E Corporation made certain tax equity investments (see "PG&E Corporation" below) and may fund similar investments in the future, resulting in additional financing needs. On November 4, 2010, PG&E Corporation entered into an Equity Distribution Agreement under which various investment banks will act as PG&E Corporation's sales agents with respect to offerings from time to time of shares of PG&E Corporation common stock having an aggregate value of up to \$400 million. The sales of the shares, if any, will be made by means of ordinary brokers' transactions on the New York Stock Exchange, or otherwise at market prices prevailing at the time of the sale or at prices related to the prevailing market prices, or at negotiated prices.

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, and finance future capital expenditures and investments.

Dividends

During the nine months ended September 30, 2010, PG&E Corporation paid common stock dividends totaling \$492 million, net of \$12 million that was reinvested in additional shares of common stock by participants in the Dividend Reinvestment and Stock Purchase Plan. On September 15, 2010, the Board of Directors of PG&E Corporation declared dividends of \$0.455 per share, totaling \$180 million, which were paid on October 15, 2010 to shareholders on record as of September 30, 2010.

During the nine months ended September 30, 2010, the Utility paid common stock dividends totaling \$537 million to PG&E Corporation.

During the nine months ended September 30, 2010, the Utility paid dividends totaling \$11 million to holders of its outstanding series of preferred stock. On September 15, 2010, the Board of Directors of the Utility declared dividends totaling \$3 million on its outstanding series of preferred stock, payable on November 15, 2010, to shareholders on record as of October 29, 2010.

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.

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The Utility's cash flows from operating activities for the nine months ended September 30, 2010 and 2009 were as follows:

(in millions)	Nine Months Ended September 30,	
	2010	2009
Net income	\$ 868	\$ 983
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,580	1,439
Allowance for equity funds used during construction	(89)	(71)
Deferred income taxes and tax credits, net	332	274
Other changes in noncurrent assets and liabilities	(286)	95
Effect of changes in operating assets and liabilities:		
Accounts receivable	(240)	20
Inventories	(65)	78
Accounts payable	15	(151)
Disputed claims and customer refunds	-	(700)
Income taxes receivable/payable	241	534
Regulatory balancing accounts, net	(14)	226
Other current assets	28	26
Other current liabilities	(33)	(62)
Other	14	3
Net cash provided by operating activities	\$ 2,351	\$ 2,694

In the nine months ended September 30, 2010, net cash provided by operating activities decreased by \$343 million compared to the same period in 2009 primarily due to an increase of \$523 million in net collateral paid by the Utility related to price risk management activities in 2010. Collateral payables and receivables are included in other changes in noncurrent assets and liabilities, other current assets, and other current liabilities in the table above. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.) The decrease also reflects \$384 million of additional net tax refunds received in 2009 compared to 2010. The remaining decreases in cash flows from operating activities consisted of miscellaneous other changes in operating assets and liabilities due to timing differences.

Decreases in operating cash flows were partially offset by a \$700 million payment to the California Power Exchange ("PX") to reduce the Utility's liability for the remaining net disputed claims in 2009 with no similar payment in 2010. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

Various factors can affect the Utility's future operating cash flows, including the timing of cash collateral payments and receipts related to price risk management activity. The Utility's cash collateral activity will fluctuate based on changes in the Utility's net credit exposure to counterparties which primarily depends on electricity and gas price movement.

The Utility's operating cash flows also will be impacted by electricity procurement costs and the timing of rate adjustments authorized to recover these costs. The CPUC has established a balancing account mechanism to adjust the Utility's electric rates whenever the forecasted aggregate over-collections or under-collections of the Utility's electric procurement costs for the current year exceed 5% of the Utility's prior-year generation revenues, excluding generation revenues for DWR contracts. The Utility also will update its forecasted 2011 electricity procurement costs in November 2010 for inclusion in the annual electric true-up proceeding, which will adjust electric and gas rates on January 1, 2011 to (1) reflect over and under-collections in the Utility's major electric and gas balancing accounts, and (2) implement various other electricity and gas revenue requirement changes authorized by the CPUC and the FERC.

Additionally, effective on June 1, 2010, the Utility began a program to provide expedited rate relief to customers. The program, which will continue through the end of 2010, includes a reduction in system bundled average electric rates coupled with a rebalancing of the residential rate tiers to reduce rates in the highest tiers. The rate reduction is expected to reduce 2010 retail electric billings by \$268 million. To provide this reduction, the Utility has accelerated the refund of various over-collections that otherwise would not be reflected in adjusted rates until January 2011 and the Utility has suspended collection of the authorized revenue requirement for the currently under-spent funds in the California Solar Initiative Program. The rate relief program will have no impact on net income for the Utility.

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

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the occurrence of storms and other events causing outages or damage to the Utility's infrastructure. Cash used in investing activities also includes the proceeds from sales and maturities of nuclear decommissioning trust investments which are 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 nine months ended September 30, 2010 and 2009 were as follows:

(in millions)	Nine Months Ended	
	September 30,	
	2010	2009
Capital expenditures	\$ (2,794)	\$ (3,022)
Decrease in restricted cash	61	732
Proceeds from sales and maturities of nuclear decommissioning trust investments	962	1,177
Purchases of nuclear decommissioning trust investments	(1,001)	(1,219)
Other	15	7
Net cash used in investing activities	\$ (2,757)	\$ (2,325)

Net cash used in investing activities increased by \$432 million in the nine months ended September 30, 2010 compared to the same period in 2009. This increase was primarily due to a \$700 million decrease in the restricted cash balance that resulted from an August 2009 payment to the PX to reduce the Utility's liability for the remaining net disputed claims, with no similar payment in 2010. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

This increase was partially offset by a decrease of \$228 million in capital expenditures mainly due to weather conditions in the first half of 2010 as compared to the same period in 2009 which delayed construction as work was shifted to emergency response; permitting, materials, and hardware purchase delays with no similar delays in 2009; and a larger decrease in 2010 than in 2009 in the amount of new customer connections as a result of the continuing economic slowdown.

Future cash flows used in investing activities are largely dependent on expected capital expenditures. (See "Capital Expenditures" below and in the 2009 Annual Report for further discussion of expected spending and significant capital projects.)

Financing Activities

The Utility's cash flows from financing activities for the nine months ended September 30, 2010 and 2009 were as follows:

(in millions)	Nine Months Ended	
	September 30,	
	2010	2009
Borrowings under revolving credit facilities	\$ 400	\$ 300
Repayments under revolving credit facilities	-	(300)
Net issuance (repayments) of commercial paper, net of discount of \$2 in 2010 and \$3 in 2009	251	(290)
Proceeds from issuance of short-term debt, net of issuance costs of \$1 in 2009	-	499
Proceeds from issuance of long-term debt, net of discount and issuance costs of \$12 in 2010 and 2009	838	847
Short-term debt matured	(500)	-
Long-term debt matured or repurchased	(95)	(909)
Energy recovery bonds matured	(285)	(273)
Preferred stock dividends paid	(11)	(10)
Common stock dividends paid	(537)	(468)
Equity contribution	170	688
Other	(40)	6
Net cash provided by financing activities	\$ 191	\$ 90

In the nine months ended September 30, 2010, net cash provided by financing activities increased by \$101 million compared to the same period in 2009. 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.

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PG&E Corporation

As of September 30, 2010, PG&E Corporation's affiliates had entered into four tax equity agreements with privately held companies to fund residential and commercial retail solar energy installations. Under these agreements, PG&E Corporation will provide payments of up to \$300 million, and in return, receive the benefits of local rebates, federal investment tax credits, and a share of these entities' customer payments. As of September 30, 2010, PG&E Corporation had made total payments of \$100 million under these tax equity agreements. PG&E Corporation's financial exposure for these arrangements is primarily limited to its lease payments and investment contributions to these entities.

In addition to the investments above, PG&E Corporation had the following material cash flows on a stand-alone basis for the nine months ended September 30, 2010 and 2009; dividend payments, interest, common stock issuance, the issuance of 5.75% Senior Notes in the principal amount of \$350 million in March 2009, net tax refunds of \$139 million in 2009, 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 2009 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

Utility

Most of the Utility's revenue requirements to recover forecasted capital expenditures are authorized in the GRC, TO rate cases, and gas transmission and storage 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 2009 Annual Report. Recent developments in authorized or proposed capital projects since the 2009 Annual Report was filed are discussed below.

Electric Distribution Reliability Program

On June 24, 2010, the CPUC authorized the Utility to recover capital expenditures of \$357 million expected to be incurred beginning in 2010 and continuing through 2013 to implement electric distribution reliability improvement projects designed to decrease the frequency and duration of electricity outages. The Utility had requested that the CPUC approve a more comprehensive six-year reliability improvement program at an estimated capital cost of \$2.0 billion. The CPUC determined that the Utility had not demonstrated the need for the entirety of the requested capital expenditure amount and authorized a scaled-back three-year program to implement portions of the Utility's proposed program. The CPUC also noted that any future investment in reliability projects can be considered in the Utility's 2014 General Rate Case and subsequent general rate cases. The CPUC adopted the Utility's proposal to set rates based on the adopted cost forecasts with a balancing account to accumulate any difference in revenue requirement based on recorded costs compared to the adopted forecast. The Utility is required to file annual reports (by March 1) to describe work performed during the previous calendar year and to include a forecast of work to be performed in the current year.

New Generation Facilities

Proposed Oakley Generation Facility

In September 2009, the Utility requested that the CPUC approve several agreements for new long-term generation resources to meet forecasted customer demand, including three power purchase agreements and an agreement for a third party to develop and construct a new 586 megawatt ("MW") natural gas-fired facility in Oakley, California that would be transferred to the Utility upon completion. The initial estimated on-line date for the Oakley facility was June 2014. On July 29, 2010, the CPUC approved the power purchase agreements but the CPUC denied the Utility's request for approval of the proposed Oakley generation facility finding that the new facility is not needed to meet forecasted customer demand. The Utility and the developer revised their agreement and on August 23, 2010, the Utility requested that the CPUC modify its prior decision and approve the Oakley project, with a guaranteed commercial availability date of June 2016. On November 2, 2010, a proposed decision was issued by the assigned CPUC administrative law judge that would deny the Utility's request. Also on November 2, 2010, an alternate proposed decision was issued by a CPUC commissioner that would approve the Oakley project with a commercial availability date of June 2016. The Utility is unable to predict the outcome of this matter.

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Humboldt Bay Generating Station

As of September 30, 2010, the Utility has incurred \$227 million to construct a 163 MW power plant to re-power the Utility's existing power plant at Humboldt Bay, which is at the end of its useful life. The CPUC has authorized the Utility to recover associated capital costs of \$239 million for the construction. Humboldt Bay commenced commercial operations in the third quarter of 2010.

Colusa Generating Station

As of September 30, 2010, the Utility has incurred capital costs of \$644 million to construct a 657 MW combined cycle generating facility located in Colusa County, California. The CPUC has authorized the Utility to recover capital costs of \$673 million for the construction of the facility. Subject to meeting operational performance requirements and other conditions, it is anticipated that the Colusa Generating Station will commence operations by the end of 2010.

New Renewable Energy Development

On April 22, 2010, the CPUC approved the Utility's proposed five-year program for the development of up to 250 MW of solar photovoltaic ("PV") facilities and to enter into power purchase agreements for an additional 250 MW of PV facilities to be developed by third parties. The Utility has been authorized to build 50 MW of utility-owned PV facilities each year of the program. If the Utility builds less than 50 MW in a program year, it may roll forward no more than 10 MW of un-deployed capacity to be developed in a subsequent program year. The first year of the five-year program began on October 11, 2010.

The CPUC has authorized the Utility to recover its actual capital costs to develop utility-owned PV facilities, subject to an aggregate price cap of up to \$1.5 billion based on the maximum 250 MW authorized to be developed by the Utility. The CPUC also established an incentive mechanism that allows the Utility shareholders to retain 10% of the savings if the average capital cost per-kilowatt of the new Utility-owned PV facilities is less than a specified maximum amount per kilowatt. The remaining 90% of any such savings would be passed through to customers. As the Utility's new PV facilities begin commercial operation, the project costs would be included in the Utility's rate base and the Utility would be entitled to earn a rate of return on the additional rate base.

PG&E Corporation

PG&E Corporation, through its subsidiary, PG&E Strategic Capital, Inc., along with Fort Chicago Energy Partners, L.P. and Williams Gas Pipeline Company, LLC, have been jointly pursuing the development of the proposed Pacific Connector Gas Pipeline, an interstate gas transmission pipeline that would connect with the proposed liquefied natural gas ("LNG") terminal in Coos Bay, Oregon being developed by Fort Chicago Energy Partners, L.P. as lead investor. The construction of the pipeline is dependent upon the construction of the LNG terminal. In December 2009, the FERC issued an order to authorize construction and operation of the LNG terminal and the pipeline. There are additional federal, state, and local permits and authorizations that must be obtained before construction can proceed. In addition, commitments must be obtained from LNG suppliers and shippers under long-term contracts of sufficient volumes to justify moving forward with construction of the LNG terminal and the pipeline. The desire of LNG suppliers to make such commitments is dependent on the world market for LNG, the price in various markets compared to the U.S. price, and the overall level of supply and demand for LNG. In the U.S., the gas supply landscape has changed considerably since the LNG terminal and pipeline were first contemplated. Enhanced drilling techniques have increased access to shale gas and created significant gas reserves which may decrease the need for LNG sourced natural gas. As such, PG&E Corporation cannot predict whether construction of the proposed LNG terminal and associated pipeline will occur nor whether PG&E Corporation will continue to invest in the proposed pipeline project.

OFF-BALANCE SHEET ARRANGEMENTS

PG&E Corporation and the Utility do not have any 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.

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CONTINGENCIES

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

REGULATORY MATTERS

This section of MD&A discusses significant regulatory developments that have occurred since the 2009 Annual Report was filed with the SEC.

2011 General Rate Case Application

On October 15, 2010, the Utility, together with the CPUC's Division of Ratepayer Advocates ("DRA"), The Utility Reform Network ("TURN"), Aglet Consumer Alliance and nearly all other intervening parties, filed a motion with the CPUC seeking approval of a settlement agreement to resolve almost all of the issues raised by the parties in the Utility's 2011 GRC. The proposed settlement agreement will be subject to public comment in the GRC proceeding and then considered by the full CPUC. In the GRC, the Utility requested an overall increase in electric distribution, gas distribution and utility-owned generation revenue requirements of \$1.1 billion over currently authorized amounts effective January 1, 2011.

Revenue Requirements

The settlement agreement proposes that the Utility's total 2011 revenue requirements be increased by \$395 million, including \$103 million related to depreciation rate changes. In addition, the settlement agreement proposes to (1) establish a new balancing account for meter reading costs outside of the GRC that offsets \$113 million requested in the GRC application and (2) remove \$30 million of requested revenue requirements from the GRC for consideration in other ratemaking proceedings. Furthermore, approximately \$44 million of the revenue requirement the Utility requested in the GRC application remains subject to litigation in the GRC.

The following table shows the differences, based on cost category, between the amount of revenue requirements included in the GRC application and the amount proposed in the settlement agreement:

(in millions)	Amounts Included	Amounts Proposed	Difference
	in the GRC Application	in the Settlement Agreement	
Operations and maintenance	\$ 1,437	\$ 1,308	\$ (129)
Customer services	498	329	(169)
Administrative and general	857	768	(89)
Less: Revenue credits	(151)	(149)	2
Franchise fees and uncollectible customer accounts, taxes (other than income taxes), and other adjustments	188	120	(68)
Depreciation, return, and income taxes	3,817	3,601	(216)
Total Revenue Requirements	\$ 6,646	\$ 5,977	\$ (669)

The following paragraphs describe the revenue requirement reductions proposed in the settlement agreement compared to the amounts included in the GRC application:

- The \$129 million reduction in revenue requirements for operations and maintenance costs reflects a lower forecast of costs for among other things, customer assistance services related to new customer connections, vegetation management, and development of utility-owned renewable generation.
- The \$169 million reduction in revenue requirements for customer services costs reflects the reduction of costs related to customer retention and economic development efforts, information technology, dynamic pricing, and meter reading. While the Utility's GRC application requested recovery of \$113 million for meter reading costs in 2011, the settlement agreement proposes that these costs will instead be recovered via a new balancing account. The balancing account would track and recover incurred meter reading costs, subject to a cap of \$76 million, and the Utility also would retain the cost savings attributable to decreased meter reading costs due to the installation of SmartMeter™ devices. The total of the balancing account recovery plus retained cost savings is estimated to approximate the \$113 million originally requested.

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- The \$89 million reduction in administrative and general reflects lower funding for various PG&E Corporation and Utility corporate service functions and lower funding for employee incentive compensation. The Utility also agreed to seek recovery of \$5 million of costs incurred in connection with the sale of property in another proceeding rather than the GRC.
- The \$68 million reduction in revenue requirements relating to franchise fees and uncollectible customer accounts, taxes (other than income), and other adjustments, includes \$44 million related to return and income taxes on the Utility's unrecovered investment in conventional electric meters that have been replaced by SmartMeter™ devices. The parties have agreed that this part of the Utility's request will be litigated as part of the GRC proceeding. If the Utility is successful, the \$44 million will be added back to the Utility's 2011 electric distribution revenue requirement. The settlement agreement also would adopt a higher uncollectible revenue factor that would be used in another CPUC proceeding to determine the amount of revenue the Utility can collect to offset uncollectible customer accounts. This is expected to result in additional revenues of approximately \$4 million.
- The \$216 million reduction in revenue requirements for depreciation, return, and income taxes consists of a \$105 million decrease driven by lower depreciation rates and a \$111 million decrease related to lower capital expenditures and other rate base adjustments. About \$49 million of the \$111 million reduction is related to the treatment of nuclear fuel and fuel oil inventory balances. Under the settlement agreement, the Utility agreed to continue recovering carrying costs on these balances at short-term interest rates (estimated to be \$1 million per year based on current rates) through the energy resource recovery balancing account ("ERRA") in accordance with the current regulatory treatment of these costs, rather than as part of the authorized GRC rate base. Another \$20 million of the reduction relates to costs to implement the California Independent System Operator's Market Redesign and Technology Update ("MRTU"). Consistent with the settlement agreement, the Utility plans to seek recovery of MRTU-related costs through the ERRA or other proceedings.

In summary, the settlement agreement proposes revenue requirements of \$3.2 billion for electric distribution (as compared to \$3.5 billion included in the GRC application), \$1.1 billion for natural gas distribution (as compared to \$1.3 billion included in the GRC application), and \$1.7 billion for electric generation operations (as compared to \$1.8 billion included in the GRC application).

Attrition Year Revenues

The settlement agreement provides for an attrition increase of \$180 million to the authorized 2011 revenues in 2012 and an additional increase of \$185 million in 2013. On a comparable basis, the Utility had requested an attrition mechanism estimated to provide increases of approximately \$262 million in 2012 and approximately \$334 million in 2013.

Balancing Accounts

The settlement agreement proposes to establish a new "one-way" balancing account for the Utility to recover up to approximately \$20 million per year for costs associated with the Utility's natural gas distribution integrity management program. If these costs are not spent during the GRC period, the unspent funds must be refunded to customers. With the exception of this proposed new one-way balancing account and the proposed meter reading balancing account discussed above, the settlement agreement proposes to retain the existing balancing account structure without any substantial changes.

Capital Additions and Rate Base

The settlement agreement is consistent with capital expenditures for 2011-2013, averaging \$2.2 billion to \$2.3 billion per year for the portions of the Utility's business addressed in the GRC. Proposed capital expenditures are lower than the amount included in the Utility's GRC application, which averaged \$2.7 billion per year, based on a lower forecast for new customer connections and lower capital expenditures for hydroelectric generation facilities, information technology systems, and fleet replacement. The ultimate amounts of capital expenditures will depend on a number of factors, including the level of operations and maintenance, administrative and general, and other costs.

The settlement agreement proposes a 2011 annual average rate base of \$16.6 billion for the portions of the Utility's business reviewed in the GRC compared with the Utility's request of \$17.2 billion. The difference of approximately \$600 million is based on the reduction of capital expenditures described above, the removal of MRTU-related capital expenditures, the continued funding of nuclear fuel and fuel oil inventory through the ERRA proceeding rather than through rate base, and the adjustment of deferred taxes to reflect the Utility's updated estimate of the impact of 2009 bonus depreciation.

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Schedule

In order to allow settlement discussions to proceed, the CPUC suspended the procedural schedule for the GRC, which had previously provided for a final decision in December 2010. It is possible that the CPUC will not issue a decision until after the end of the year. On August 6, 2010, the Utility filed a motion requesting that, regardless of the timing of a CPUC decision, any revenue requirement change be effective on January 1, 2011. That motion remains pending before the CPUC.

PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the settlement agreement.

Electric Transmission Owner Rate Cases

On July 27, 2010, the FERC approved an uncontested settlement of the Utility's 12th TO rate case. The settlement sets the Utility's annual retail transmission base revenue requirement at \$875 million effective March 1, 2010. Retail electric rates were adjusted on June 1, 2010 to reflect the revenue requirement adopted in the settlement and the Utility has reserved the difference between revenues collected in the rates requested by the Utility in its TO rate application, from March 1, 2010 until May 31, 2010, and the rates agreed to in the settlement. As a result, the settlement will not impact the Utility's results of operations or financial condition. The Utility will refund any over-collected amounts to customers, with interest, through an adjustment to rates in 2011.

On July 28, 2010, the Utility filed an application with the FERC requesting an annual retail transmission revenue requirement of \$1.0 billion. The proposed rates represent an increase of \$150 million over current authorized revenue requirements. On September 30, 2010, the FERC accepted the Utility's application and also permitted the proposed rates to become effective on March 1, 2011, subject to refund following the conclusion of hearings and the outcome of judge-supervised settlement discussions.

On June 17, 2010, the FERC issued a notice of proposed rulemaking and established a proceeding to examine, among other issues, whether to change the FERC's existing policy that provides incumbent traditional public utilities a "right of first refusal" to own, construct, and operate transmission facilities within their respective service territories. The rules that the FERC adopts in this proceeding may introduce additional competition from merchant or independent transmission project developers for the construction of certain transmission facilities that do not exist today. The rules that the FERC may adopt are not expected to impact the Utility's transmission investment in 2010 or 2011.

2011 Gas Transmission and Storage Rate Case

In the Utility's 2011 gas transmission and storage rate case, the CPUC will 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 and continuing through 2014.

Proposed Settlement Agreement

On August 20, 2010, the Utility and other parties, including TURN and the DRA, requested the CPUC to approve a proposed settlement agreement, known as the Gas Accord V Settlement Agreement ("Gas Accord V"), to set the Utility's gas transmission and storage rates and associated revenue requirements, as well as the market structure, for 2011 through 2014. The proposed Gas Accord V also would extend a majority of the Gas Accord IV's terms and conditions of natural gas transportation and storage services. (See the 2009 Annual Report for a discussion of the Gas Accord IV.) The CPUC's approval of the proposed Gas Accord V is subject to the resolution of several objections raised by San Diego Gas & Electric Company and Southern California Gas Company regarding their rights and obligations under the proposed agreement.

The Gas Accord V proposes a 2011 natural gas transmission and storage revenue requirement of \$514 million, an increase of \$52 million over the 2010 adopted revenue requirement. The proposed revenue requirement for 2012 is \$541 million, \$565 million for 2013, and \$582 million for 2014. The Gas Accord V proposes average annual capital expenditures of \$174 million and average annual depreciation costs of \$112 million. The Gas Accord V provides for a 2011 operating and maintenance expense level of \$105 million which would increase at an annual average rate of 2% for 2012 through 2014.

Under the proposed Gas Accord V, approximately 45% of the authorized revenue requirements, primarily those costs allocated to core customers, would continue to be assured of recovery through balancing account mechanisms and fixed reservation charges. The Utility's ability to recover its remaining revenue requirements would continue to depend on throughput volumes and the extent to which non-core customers and other shippers contract for firm transmission services. To reduce the Utility's risk of non-recovery on these remaining revenue requirements, the proposed settlement agreement includes a revenue sharing mechanism. An under-collection or over-collection of the remaining revenue requirements associated with backbone transmission services (35% of authorized revenue requirement) would be shared equally between the Utility and customers (both core and non-core). Customers would be allocated 75% of any under-collection or over-collection of remaining revenue requirements associated with local transmission services (13% of authorized revenue requirement). Customers also would be allocated 75% of any over-collection in

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remaining revenue requirements associated with storage services (7% of authorized revenue requirement), but the Utility would be at risk for 100% of a net under-collection. The Gas Accord V provides for additional cost recovery mechanisms for costs that are difficult to forecast, such as the cost of electricity used to operate natural gas compressor stations and costs that are determined in other Utility regulatory proceedings.

Safety Phase

On October 15, 2010, an additional phase was added to the Utility's 2011 Gas Transmission and Storage Rate Case to address the Utility's natural gas pipeline safety, integrity, and reliability measures and the Utility's emergency response procedures used in its natural gas transmission and storage operations. This new "safety phase" will focus on ensuring the safety and reliability of the Utility's natural gas transmission and storage system. The CPUC will review and consider the types of protocols and procedures that the Utility should have in place or that the CPUC should immediately order to ensure the safe operation of the Utility's gas transmission and storage operations over the next four years. The ruling notes that the new safety phase is distinct from the NTSB's and the CPUC's pending investigations into the cause of the San Bruno Accident, any proceedings that may be opened as a result of the CPUC's investigation, and any federal or state legislation that may be adopted. Opening comments on the safety phase issues are due November 22, 2010, with reply comments due on December 27, 2010. A proposed decision on these issues is expected in February or March 2011.

Request to Make Rate Changes Effective on January 1, 2011

On October 8, 2010, the parties requested that the CPUC issue a final decision by December 21, 2010 to allow the Utility to adjust 2011 rates (upward or downward) from the date the CPUC issues a final decision on the Gas Accord V assuming the final decision is issued after January 1, 2011. If the CPUC does not issue a decision on this request by January 1, 2011, the terms of the Gas Accord IV provide that the interim transmission and storage rates beginning January 1, 2011 will equal the rates in effect on December 31, 2010, plus a two percent escalator for local transmission rates .

Procedural Schedule

The CPUC's procedural schedule calls for the CPUC to issue a final decision on the Gas Accord V and the litigated issues on or before March 10, 2011. It is expected that the CPUC's procedural schedule for the safety phase will be set in early January 2011.

PG&E Corporation and the Utility are unable to predict whether or when the CPUC will approve the proposed Gas Accord V. PG&E Corporation and the Utility are also unable to predict what actions the CPUC may require the Utility to take as a result of the new safety phase and whether the costs the Utility incurs to take such actions would be recoverable in whole or part.

Finally, the costs contemplated under the Gas Accord V do not include potential costs associated with the Utility's proposed Pipeline 2020 program of initiatives, announced on October 12, 2010, to work with regulators and industry experts to strengthen the natural gas system over the next decade. The program is expected to 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. As part of this program, the Utility plans to create a new non-profit entity to research and develop next-generation pipeline inspection and diagnostic tools. The Utility will provide \$10 million to fund this new entity at no cost to customers.

Energy Efficiency Programs and Incentive Ratemaking

The CPUC has established a ratemaking mechanism to provide incentives to the California investor-owned utilities to meet the CPUC's energy savings goals through implementation of the utilities' 2006-2008 energy efficiency programs. In accordance with this mechanism, the CPUC has awarded the Utility interim incentive revenues totaling \$75 million through December 31, 2009 based on the energy savings achieved through implementation of the Utility's energy efficiency programs during the 2006 through 2008 program cycle.

On September 28, 2010, a proposed decision was issued by the assigned CPUC administrative law judge recommending that no additional incentive revenues be awarded to the Utility. Also on September 28, 2010, an alternate proposed decision was issued by a CPUC commissioner that recommends that the Utility be awarded additional incentive revenues of \$40 million, an amount equal to the amounts that had been held back from the interim awards.

The CPUC is scheduled to issue a final decision to complete the true-up process by the end of 2010. PG&E Corporation and the Utility are unable to predict the amount, if any, of additional incentive revenues the Utility may receive for the 2006-2008 program cycle.

The CPUC's rulemaking proceeding to consider modifications to the existing incentive ratemaking mechanism that would apply to future energy efficiency program cycles is still pending. It is uncertain when the CPUC will issue a decision in this proceeding.

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Direct Access

As authorized by California Senate Bill 695, on March 11, 2010, the CPUC adopted a plan to re-open “direct access” on a limited and gradual basis to allow eligible customers of the three California investor-owned utilities to purchase electricity from independent electric service providers rather than from a utility. Effective April 11, 2010, all qualifying non-residential customers became eligible to take direct access service subject to annual and absolute caps. It is estimated that the total amount of direct access that will be allowed in the Utility’s service territory by the end of the four-year phase-in period will be equal to approximately 11% of the Utility’s total annual retail sales at the end of the period, roughly the highest level that was reached before the CPUC suspended direct access. Further legislative action is required to exceed these limits. The adopted phase-in schedule is designed to provide enough lead time for the utilities to account for small shifts in load and avoid unwarranted cost shifting and stranded costs.

2009 Energy Resource Recovery Account Compliance Proceeding

The Utility recovers its electricity procurement costs and the fuel costs for the Utility’s own generation facilities (but excluding the costs of electricity allocated to the Utility’s customers under DWR contracts) through ERRA, a balancing account that tracks the difference between (1) billed/unbilled ERRA revenues and (2) electric procurement costs incurred under the Utility’s authorized procurement plans. To determine rates used to collect ERRA revenues, each year the CPUC reviews the Utility’s forecasted procurement costs related to power purchase agreements and generation fuel expense and approves a forecasted revenue requirement. The CPUC also performs an annual compliance review of the procurement activities recorded in the ERRA to ensure that the Utility’s procurement activities are in compliance with its approved procurement plans.

The Utility’s 2009 ERRA compliance review proceeding is currently pending before the CPUC. On July 9, 2010, the DRA filed testimony to recommend that the CPUC disallow \$176 million of costs that the DRA estimates the Utility incurred in 2009 to buy power during 110 outages of the Utility’s own generation facilities. The DRA argued that since the Utility did not present evidence of the reasonableness of its outage management activities and the related replacement costs in its initial application and testimony, these costs should be disallowed. On August 4, 2010, the CPUC administrative law judge overseeing the proceeding granted the Utility’s request to strike the DRA’s testimony. The CPUC is expected to issue a final decision in this proceeding by December 31, 2010.

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 2009 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. (In July 2010, PG&E Corporation and the Utility posted their annual Corporate Responsibility and Sustainability Report at <http://www.pgecorp.com>. This report includes the Utility’s third-party verified GHG emissions data for 2008. This report is not incorporated by reference into this quarterly report.)

Recent developments since the 2009 Annual Report was filed are discussed below.

Climate Change

AB 32 requires the gradual reduction of GHG emissions in California to 1990 levels by 2020 on a schedule beginning in 2012. (See “Environmental Matters” in the 2009 Annual Report.) On November 2, 2010, California voters defeated a ballot initiative, Proposition 23, to suspend AB 32.

In December 2008, the California Air Resources Board (“CARB”), the state agency charged with setting and monitoring GHG and other emission limits, adopted a scoping plan that contains recommendations for achieving the maximum technologically feasible and cost-effective GHG reductions to meet the 2020 reduction target. These recommendations include increasing renewable energy supplies, increasing energy efficiency goals, expanding the use of combined heat and power facilities, and developing a multi-sector cap-and-trade program.

On September 23, 2010, the CARB adopted regulations that require virtually all load-serving entities, including the Utility, to increase their deliveries of renewable energy to meet specific annual targets. For 2012, 2013, and 2014, the amount of electricity delivered from renewable energy resources must equal at least 20% of total energy deliveries, increasing to 24% in 2015, 2016, and 2017, 28% in 2018 and 2019, and 33% in 2020 and beyond. Regulated load-serving entities are allowed to use an unlimited number of tradable renewable energy credits (“RECs”) to comply. (A tradable REC refers to a certificate of proof of the procurement of the

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green attributes unbundled from the associated energy. The certificate may be transferred to any third party and resold.) The CARB can impose penalties for failure to meet the targets but it is unclear how the penalties would be calculated or whether the total penalties are subject to an annual maximum. For example, the CPUC has established an annual maximum penalty of \$25 million for failure to meet the existing renewable portfolio standard (“RPS”) established under California law. Further, the CARB did not adopt “flexible compliance rules” such as those used by the CPUC to determine compliance with current RPS requirements. The CARB has directed its staff to modify the regulations to address concerns about the potential for excessive penalties. It is uncertain when the modified final regulations will be issued.

In addition, on October 28, 2010, the CARB issued proposed cap-and-trade regulations and proposed amendments to the existing regulation for the mandatory reporting of GHG emissions. Following a 45-day public comment period, these regulations will be presented for the CARB’s consideration in mid-December 2010. If adopted by the CARB and approved by the Office of Administrative Law, the regulations would set an annual cap on GHG emissions from 2012 to 2020 and allow companies to buy and sell emission allowances or offsets to meet the applicable cap. Some emission allowances would be allocated to the electric sector utilities at no cost for the benefit of their customers. The price of other emission allowances would be subject to a price collar. The CARB has indicated that the natural gas and transportation-fuel sectors will not be included in the cap-and-trade program until 2015. The ultimate financial impact of the new cap-and-trade system will depend on various factors, including the quantity of allowances that are freely allocated to utilities for customer benefit, the actual market price of emissions allowances over time, the availability of emission offsets, and the extent to which California’s cap-and-trade program is linked to other state, regional or national programs.

Renewable Energy Resources

Current California law establishes a RPS that requires California retail sellers of electricity, such as the Utility, to increase their deliveries of renewable energy (such as biomass, hydroelectric facilities with a capacity of 30 MW or less, wind, solar, and geothermal energy) each year, so that the amount of electricity delivered from these eligible renewable resources equals at least 20% of their total retail sales by the end of 2010. If a retail seller is unable to meet its target for a particular year, the current CPUC “flexible compliance” rules allow the retail seller to use future energy deliveries from already-executed contracts to satisfy any shortfalls, provided those deliveries occur within three years of the shortfall. For the year ended December 31, 2009, the Utility’s RPS-eligible renewable resource deliveries equaled 14.4% of its total retail electricity sales. Most of the renewable energy that was delivered was purchased by the Utility from third parties, mainly under agreements with qualifying facility generators, irrigation districts, and other bilateral contracts. As of September 30, 2010, the Utility believes it will meet the RPS mandate for 2010 through reliance on the CPUC’s flexible compliance rules. On September 1, 2010, the California Legislature failed to pass Senate Bill 722 which proposed to establish a 33% RPS by 2020. Additional legislation may be considered and adopted in the future. In addition, as described above, the CARB has adopted regulations imposing a 33% renewable energy standard to be met by 2020 to help reduce GHG emissions as required by AB 32.

Uncertainty still exists regarding whether RECs can be used to comply with the current RPS requirements. The

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CPUC issued a decision in March 2010 which, among other provisions, imposes a price cap of fifty dollars per tradable REC, and permits investor-owned utilities to use tradable RECs to comply with up to 25% of their annual RPS procurement target in any year and carry over any excess RECs for compliance in future years. For purposes of computing the annual limit, the CPUC decision classifies power-purchase contracts with out-of-state renewable generation facilities as RECs. Most of the Utility's power-purchase contracts with out-of-state renewable generation facilities would be included in the computation of the 25% limit, negatively affecting the Utility's ability to meet the RPS. The CPUC stayed its decision in May 2010 after various parties, including the Utility, requested the CPUC to modify the decision. A proposed decision has been issued which, if adopted by the CPUC, would lift the stay, reaffirm the price cap, increase the REC limit to 30%, and exclude power-purchase contracts for out-of-state-renewable resources from the 30% limit if the contracts had been executed and approved by the CPUC before March 11, 2010. The proposed decision provides that the annual 30% limit and price cap would expire automatically on December 31, 2013. On October 25, 2010, an alternate proposed decision was issued that, if approved by the CPUC, would lift the stay, reaffirm the price cap and annual 25% limit on REC transactions as approved in the CPUC's March 2010 decision, and reinstate provisions in the March 2010 decision that would increase the REC usage cap if approved contracts as of the effective date of that decision would cause a utility to be over the cap. Otherwise, if a utility subsequently exceeds the cap, the utility may bank forward the deliveries to a year in which the cap is not exceeded. Furthermore, the alternate proposed decision would require the annual limit and price cap to remain in effect until it is superseded by a CPUC decision or an act of California Legislature. If the alternate proposed decision is approved, renewable energy contracts submitted after May 6, 2010 (the date the stay becomes effective) must be re-filed to comply with the CPUC's March 2010 decision. It is uncertain when the CPUC will take action on the proposed decisions.

Water Quality

There is continuing uncertainty about the status of state and federal regulations issued under Section 316(b) of the Clean Water Act, which require 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. Although the U.S. EPA will not issue draft revised regulations until February 2011, on May 4, 2010, the California Water Resources Control Board ("Water Board") 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. (See Note 16 of the Notes to the Consolidated Financial Statements in the 2009 Annual Report for more information.) 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 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 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. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements, for a discussion of estimated environmental remediation liabilities.)

OTHER MATTERS

SmartMeter™ Technology

The CPUC has authorized the Utility to recover \$2.2 billion in estimated project costs, including \$1.8 billion of capital expenditures to install approximately 10 million advanced electric and gas meters throughout the Utility's service territory by the end of 2012. As of September 30, 2010, the Utility has incurred \$1.9 billion in connection with its SmartMeter™ program. In light of unanticipated cost pressures, including those relating to customer-related communications and outreach issues that have arisen since the summer of 2009, the Utility forecasts that total costs may exceed \$2.2 billion. The CPUC also has authorized the Utility to recover in rates 90% of up to \$100 million in costs that exceed \$2.2 billion without a reasonableness review. Costs incurred by the Utility in

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excess of \$2.3 billion would be subject to a reasonableness review for recovery. The Utility is unable to predict whether it will incur a material amount of costs in excess of these authorized amounts and whether the Utility would be able to recover such additional costs through rates.

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. These meters will allow the implementation of "dynamic pricing" rates that are designed to reflect the higher cost of electricity during periods of high demand. The CPUC has ordered the Utility to implement certain dynamic pricing rates for some customer classes by February 2011. The Utility has requested that the CPUC extend the date to November 2011 to allow the Utility more time to develop the web-based tools necessary for customers to evaluate the new rates.

As of September 30, 2010, the Utility has 6.9 million meters installed. Based on the tests that the Utility has performed, more than 99% of the meters perform accurately as designed and within expectations. The Utility has not found any material design defects, but has found, as is to be expected with any new technology applied on this scale, that a small percentage of the meters recorded inaccurate energy usage, were not properly installed, or were affected by issues relating to the meter's data storage capabilities or wireless communication features. When issues are identified, the Utility is taking prompt action with the technology and services vendors to remediate the issues. The Utility has implemented new pre-installation quality control procedures. The Utility also has increased its customer education and outreach efforts, including posting weekly data reports on its website to inform customers and the public about the findings of the Utility's assessment.

On June 17, 2010, the City and County of San Francisco ("CCSF") filed a petition requesting the CPUC to temporarily suspend the installation of additional SmartMeter™ devices until the CPUC has completed its independent assessment. CCSF also filed a motion requesting expedited treatment of its petition. Several municipalities filed pleadings in support of CCSF's petition. On September 2, 2010, the CPUC released the report of its independent consultant that was engaged by the CPUC to assess the Utility's SmartMeter™ program, including meter and billing accuracy, customer complaints, end-to-end operational processes, and overall program planning and performance. The consultant's evaluation report found that the Utility's SmartMeter™ devices and related billing processes perform accurately and as designed. On September 22, 2010, a CPUC administrative law judge denied CCSF's request for expedited treatment of its petition and requested the parties to submit comments on CCSF's petition in light of the consultant's report. On October 15, 2010, the Utility filed comments urging the CPUC to dismiss CCSF's petition given the reports' findings on meter and billing accuracy. Other parties have requested that the CPUC take additional steps before concluding its investigation.

The CPUC is also considering two additional requests from private groups to halt the installation of SmartMeter™ devices based on concerns about the health, environmental, and safety impacts of the radio frequency ("RF") technology on which the Utility's SmartMeter™ program relies. On October 26, 2010, a proposed decision was issued that, if adopted by the CPUC, would dismiss one of the requests on the basis that the SmartMeter™ devices are licensed and certified by the Federal Communications Commission ("FCC") and comply with all FCC requirements.

On October 25, 2010, the Superior Court in Bakersfield, California, granted the Utility's request to dismiss a class action lawsuit that had alleged that the new meters, wireless network, and software and billing system led to electric bill overcharges. The court agreed with the Utility that the lawsuit should be dismissed because, among other reasons, the CPUC retains exclusive jurisdiction over the issues raised in the lawsuit. The court's order permits the plaintiffs to file a new lawsuit within 20 days in lieu of appealing the dismissal. In addition, on September 17, 2010, the lawyer that filed the Superior Court class action lawsuit filed an application at the CPUC, on behalf of customers, requesting that the CPUC modify its prior decisions and shift the costs of the Utility's SmartMeter™ technology upgrade to the Utility. On October 27, 2010, the Utility requested that the CPUC dismiss the application because it improperly seeks to re-litigate issues the CPUC has already decided on.

A California State Senate committee is continuing to investigate and review the deployment of the "smart grid" throughout California, focusing on the Utility's SmartMeter™ program and the integrity and reliability of new metering technologies and the consumer protections in place with respect to billing, disconnection, and real-time pricing. The Utility has provided all requested information to the committee about the installed meters. The committee is expected to submit its report to the California Senate, including recommendations for appropriate legislation, by November 30, 2010.

In addition, class action complaints have been filed in federal and California state court against the various companies that have supplied SmartMeter™ devices, components, and software to the Utility. (These complaints do not name the Utility as a defendant.) These complaints allege that the new meters report electric consumption in amounts materially greater than the electricity that the class members actually consumed, resulting in electric bill overcharges.

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The Utility is continuing to install the new meters. Various municipalities in the Utility's service territory have approved ordinances to either suspend or prohibit the installation of SmartMeter™ devices primarily based on concerns about the health, environmental, and safety impacts of the RF technology on which the Utility's SmartMeter™ program relies. The CPUC has stated that such ordinances would interfere with the CPUC's exclusive jurisdiction over the Utility's SmartMeter™ program.

The outcome of the matters discussed above may have an effect on the Utility's ability to recover costs to implement advanced metering if the CPUC finds that the costs are not reasonable or are otherwise disallowed. Further, if the Utility is prohibited from continuing to install the new meters or if the Utility otherwise fails to recognize the expected benefits of its advanced metering infrastructure, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected.

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 risk mitigation purposes 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.

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 \$14 million at September 30, 2010. The Utility's high, low, and average values-at-risk at September 30, 2010 were \$20 million, \$10 million, and \$14 million, respectively.

See Note 7 of the Notes to the Condensed Consolidated Financial Statements for further discussion of price risk management activities.

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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 September 30, 2010, 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 \$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 failed 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.

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 September 30, 2010 and December 31, 2009:

(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%
September 30, 2010	\$ 189	\$ 26	\$ 163	2	\$ 117
December 31, 2009	\$ 202	\$ 24	\$ 178	3	\$ 154

⁽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 rupture of a natural gas transmission pipeline owned and operated by the Utility in the City of San Bruno, California on September 9, 2010, 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 2009 Annual Report. They include:

- regulatory assets and liabilities;
- environmental remediation liabilities;
- asset retirement obligations;
- accounting for income taxes; and
- pension and other postretirement plans.

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For the nine months ended September 30, 2010, 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. New critical accounting estimates are described below.

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 September 30, 2010, 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 September 30, 2010 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

Diablo Canyon Power Plant

On October 1, 2010, the state Water Board 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 policy could affect future negotiations between the 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, see PG&E Corporation's and the Utility's joint Annual Report on Form 10-K for the year ended December 31, 2009 and Part II, Item 1, "Legal Proceedings" in PG&E Corporation's and the Utility's combined Quarterly Report on Form 10-Q for the quarter ended June 30, 2010. For more information about the state once-through cooling policy, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Matters – Water Quality" above.

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.

San Bruno Accident

Following the San Bruno Accident, various lawsuits, including two class action lawsuits, have been filed by residents of San Bruno in the San Mateo County Superior Court and San Francisco County Superior Court against PG&E Corporation and the Utility. The class action lawsuits include a demand that the \$100 million the Utility announced would be available for assistance be placed under court supervision. These lawsuits allege causes of action for strict liability, negligence, public nuisance, private nuisance, and declaratory relief. 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. The other lawsuits, including some that have been filed in San Francisco County Superior Court, seek to recover damages for wrongful death, property damage, and personal injury.

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 most 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 September 30, 2010. PG&E Corporation and the Utility are unable to predict the amount and timing of such 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 – Explosion and Fires in San Bruno, California."

ITEM 1A. RISK FACTORS

A discussion of the significant risks associated with investments in the securities of PG&E Corporation and the Utility is set forth under the heading "Management's Discussion and Analysis of Financial Condition and Results of Operations - Risk Factors" in the 2009 Annual Report.

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.

PG&E Corporation's and the Utility's financial statements for the period ended September 30, 2010 reflect a provision of \$220 million for estimated third-party claims related to the San Bruno Accident, including personal injury and property damage claims, damage to infrastructure, emergency response, and other damage claims. Various lawsuits, including two class action lawsuits, have been filed by residents of San Bruno against PG&E Corporation and the Utility seeking to recover damages for wrongful death, property damage, and personal injury and seeking other relief. The process for estimating costs associated with third-party claims relating to the San Bruno Accident requires management to exercise significant judgment based on a number of assumptions and subjective factors. The Utility estimates that it may incur as much as \$400 million for third-party claims depending on the final outcome of the NTSB and CPUC investigations and the number, nature, and value of third-party claims.

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As more information becomes known, including information resulting from the NTSB and CPUC investigations, management's estimates and assumptions regarding the financial impact of the San Bruno Accident may change. A change in management's estimates or assumptions could result in an adjustment that would have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations during the period in which such change occurred.

The Utility maintains liability insurance for damages in the approximate amount of \$992 million after a \$10 million deductible. PG&E Corporation and the Utility currently consider it likely that most of the costs the Utility incurs for third-party claims relating to the San Bruno Accident will ultimately be covered by this insurance. However, PG&E Corporation and the Utility are unable to predict the timing and amount of insurance recoveries.

If the Utility records losses in connection with third-party claims related to the San Bruno Accident that materially exceed the amount it has accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially adversely affected in the reporting periods during which additional charges are recorded depending on whether and when the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals during the same reporting periods.

In addition, the Utility currently anticipates that it will incur additional unbudgeted costs for inspection and maintenance of its natural gas transmission system. The Utility also may incur costs, beyond the amount currently anticipated, in response to NTSB or CPUC orders or requests as the investigations continue. Further, state or federal legislation may be enacted that would require the Utility to incur additional costs by mandating various changes, including changes to its operating practice standards for natural gas transmission operations and safety, use of certain types of inspection methods and equipment, and installations of certain types of valves. If the Utility incurs a material amount of costs that it is unable to recover through rates or offset through operational or other cost savings, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be materially and adversely affected.

Finally, if it is determined that the Utility did not comply with applicable statutes, regulations, rules, tariffs, or orders in connection with the San Bruno Accident or in connection with the operations or maintenance of the Utility's natural gas system, and the Utility is ordered to pay a material amount in customer refunds, penalties, or other amounts, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows would be materially and adversely affected.

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

During the quarter ended September 30, 2010, PG&E Corporation made equity contributions totaling \$40 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. The Utility did not make any sales of unregistered equity securities during the quarter ended September 30, 2010.

Issuer Purchases of Equity Securities

PG&E Corporation common stock:

Period	Total Number of Shares Purchased	Average Price Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet be Purchased Under the Plans or Programs
July 1 through July 31, 2010	496 ⁽¹⁾	\$ 42.56	-	\$ -
August 1 through August 31, 2010	-	-	-	-
September 1 through September 30, 2010	-	-	-	-
Total	496	\$ 42.56	-	\$ -

⁽¹⁾ Shares of PG&E Corporation common stock tendered to pay stock option exercise price.

During the quarter ended September 30, 2010, 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 nine months ended September 30, 2010 was 3.32. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the nine months ended September 30, 2010 was 3.26. 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 333-149361 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 nine months ended September 30, 2010 was 3.10. 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. 333-149360 relating to its senior notes.

ITEM 6. EXHIBITS

4.1	Tenth Supplemental Indenture dated as of September 15, 2010 relating to the issuance of \$550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Current Report on Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1)
4.2	Eleventh Supplemental Indenture dated as of October 12, 2010 relating to the issuance of \$250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due October 11, 2011 (incorporated by reference to Pacific Gas and Electric Company's Current Report on Form 8-K dated October 12, 2010 (File No. 1-2348), Exhibit 4.1)
*10.1	Supplemental Executive Retirement Plan of PG&E Corporation as amended effective as of September 15, 2010
*10.2	PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010
*10.3	PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011
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
***101.CAL	XBRL Taxonomy Extension Calculation
***101.DEF	XBRL Extension Definition
***101.LAB	XBRL Taxonomy Extension Label
***101.PRE	XBRL Taxonomy Extension Presentation
*	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: November 4, 2010

EXHIBIT INDEX

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***101.LAB	XBRL Taxonomy Extension Label
***101.PRE	XBRL Taxonomy Extension Presentation
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**	Pursuant to Item 601(b)(32) of SEC Regulation S-K, these exhibits are furnished rather than filed with this report.
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SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
OF
PG&E CORPORATION
(As Amended Effective as of September 15, 2010)

This is the controlling and definitive statement of the Supplemental Executive Retirement Plan (“PLAN”) ¹ for ELIGIBLE EMPLOYEES of PG&E Corporation (“CORPORATION”), Pacific Gas and Electric Company (“COMPANY”) and such other companies, affiliates, subsidiaries, or associations as the BOARD OF DIRECTORS may designate from time to time. The PLAN is the successor plan to the Supplemental Executive Retirement Plan of the COMPANY. The PLAN as contained herein was first adopted effective January 1, 2005.

ARTICLE 1

DEFINITIONS

1.01 Basic SERP Benefit shall mean the benefit described in Section 2.01.

1.02 Board or Board of Directors shall mean the BOARD OF DIRECTORS of the CORPORATION or, when appropriate, any committee of the BOARD which has been delegated the authority to take action with respect to the PLAN.

1.03 Company shall mean the Pacific Gas and Electric Company, a California corporation.

1.04 Corporation shall mean PG&E Corporation, a California corporation.

1.05 Eligible Employee shall mean individuals who are (1) (a) employees of the COMPANY or, with respect to PG&E Corporation, PG&E Corporation Support Services, Inc., and PG&E Corporation Support Services II, Inc. only, (i) prior to April 1, 2007, were employees who transferred to PG&E Corporation, PG&E Corporation Support Services, Inc., or PG&E Corporation Support Services II, Inc. from Pacific Gas and Electric Company; or (ii) after March 31, 2007, all employees, and (b) officers in Officer Bands I-V, or (2) such other employees of the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc., PG&E Corporation Support Services II, Inc., or such other companies, affiliates, subsidiaries, or associations, as may be designated by the Chief Executive Officer of the CORPORATION. ELIGIBLE EMPLOYEES shall not include employees who retired prior to January 1, 2005, or whose employment relationship with any of the PARTICIPATING EMPLOYERS was otherwise terminated prior to January 1, 2005.

1.06 STIP Payment shall mean amounts received by an ELIGIBLE EMPLOYEE under the Short-Term Incentive Plan maintained by the CORPORATION.

1.07 Participating Employer shall mean the COMPANY, the CORPORATION, PG&E Corporation Support Services, Inc., PG&E Corporation Support Services II, Inc., and any other companies, affiliates, subsidiaries or associations designated by the Chief Executive Officer of the CORPORATION.

¹ Words in all capitals are defined in Article I.

1.08 Plan shall mean the Supplemental Executive Retirement Plan (“SERP”) as set forth herein and as may be amended from time to time.

1.09 Plan Administrator shall mean the Employee Benefit Committee or such individual or individuals as that Committee may appoint to handle the day-to-day affairs of the PLAN.

1.10 Retirement Plan shall mean the Pacific Gas and Electric Company Retirement Plan for Management Employees.

1.11 Salary shall mean the base salary received by an ELIGIBLE EMPLOYEE. SALARY shall not include amounts received by an employee after such employee ceases to be an ELIGIBLE EMPLOYEE. For purposes of calculating benefits under the PLAN, SALARY shall not be reduced to reflect amounts that have been deferred under the PG&E Corporation Supplemental Retirement Savings Plan.

1.12 Service shall mean “credited service” as that term is defined in the RETIREMENT PLAN or, if the Nominating and Compensation Committee of the BOARD OF DIRECTORS has granted an adjusted service date for an ELIGIBLE EMPLOYEE, “credited service” as calculated from such adjusted service date. In no event, however, shall SERVICE include periods of time after which an officer has ceased to be an ELIGIBLE EMPLOYEE.

ARTICLE 2

SERP BENEFITS

2.01 The BASIC SERP BENEFIT payable from the PLAN shall be a monthly annuity with an annuity start date of the later of (a) the first of the month following the month in which the ELIGIBLE EMPLOYEE has a separation from service (as provided under Code Section 409A and related guidance), or (b) the first of the month following the ELIGIBLE EMPLOYEE’s 55th birthday; provided, however, that no payments under the PLAN shall be made until the seventh month following the annuity start date. The first payment shall consist of the monthly annuity payment for the seventh month, plus the first six monthly annuity payments, including interest calculated at a rate to reflect the CORPORATION’s marginal cost of funds. The monthly amount of the BASIC SERP BENEFIT shall be equal to the product of:

$1.7\% \times \text{the average of three highest calendar years' combination of SALARY and STIP PAYMENT for the last ten years of SERVICE} \times \text{SERVICE} \times 1/12.$

In computing a year’s combination of SALARY and STIP PAYMENT, the year’s amount shall be the sum of the SALARY and STIP PAYMENT, if any, paid or payable in the same calendar year. If an ELIGIBLE EMPLOYEE has fewer than three years’ SALARY, the average shall be the combination of SALARY and STIP PAYMENT for such shorter time, divided by the number of years and partial years during which such employee was an ELIGIBLE EMPLOYEE.

The BASIC SERP BENEFIT is further reduced by any amounts paid or payable from the RETIREMENT PLAN, calculated before adjustments for marital or joint pension option elections.

The BASIC SERP BENEFIT is a benefit commencing at age 65. The amount of the benefit payable shall be reduced by the appropriate age and service factors contained in the RETIREMENT PLAN applicable to such employee. For such calculations, the service factor shall be SERVICE as defined in the PLAN.

In computing amounts payable from the RETIREMENT PLAN as an offset to the benefit payable from this PLAN, the RETIREMENT PLAN benefit shall be calculated as though the ELIGIBLE EMPLOYEE elected to receive a pension from the RETIREMENT PLAN commencing on the same date as benefits from this PLAN.

2.02 For ELIGIBLE EMPLOYEES of the PARTICIPATING EMPLOYERS, who transfer from any of said companies to another subsidiary or affiliate, the principles of Section 10 of the RETIREMENT PLAN shall govern the calculation of benefits under this PLAN.

2.03 An ELIGIBLE EMPLOYEE may elect to have his BASIC SERP BENEFIT paid in any one of the following forms that are actuarially equivalent within the meaning of Treasury Regulations Section 1.409A-2(b)(ii), with the first annuity payment commencing at the time set forth in Section 2.01:

(a) BASIC SERP BENEFIT, or a reduced BASIC SERP BENEFIT as calculated under Section 2.02, paid as a monthly annuity for the life of the ELIGIBLE EMPLOYEE with no survivor's benefit.

(b) A monthly annuity payable for the life of the ELIGIBLE EMPLOYEE with a survivor's option payable to the ELIGIBLE EMPLOYEE's joint annuitant beginning on the first of the month following the ELIGIBLE EMPLOYEE's death. Subject to the requirements of Treasury Regulations Section 1.409A-2(b)(ii), the factors to be applied to reduce the BASIC SERP BENEFIT to provide for a survivor's benefit shall be the factors which are contained in the RETIREMENT PLAN and which are appropriate given the type of joint pension elected and the ages and marital status of the joint annuitants.

An ELIGIBLE EMPLOYEE may make this election by the latest date permitted by the PLAN ADMINISTRATOR and in compliance with the rules of Treasury Regulations Section 1.409A-2(b)(2)(ii).

2.04 Annuities payable to an ELIGIBLE EMPLOYEE who is receiving a (i) BASIC SERP BENEFIT, (ii) a BASIC SERP BENEFIT reduced to provide a survivor's benefit to a joint annuitant, or (iii) a joint annuitant who is receiving a survivor's benefit shall be decreased by any additional amounts which can be paid from the RETIREMENT PLAN where such additional amounts are due to increases in the limits placed on benefits payable from qualified pension plans under Section 415 of the Internal Revenue Code. The amount of any such decrease shall be adjusted to reflect the type of pension elected by an ELIGIBLE EMPLOYEE under the RETIREMENT PLAN and this PLAN.

ARTICLE 3

SURVIVOR BENEFITS

3.01 In the event that an ELIGIBLE EMPLOYEE who has accrued a benefit under this PLAN dies prior to the date that a BASIC SERP BENEFIT would otherwise commence, the

PLAN ADMINISTRATOR shall pay a survivor's benefit ("SURVIVOR'S BENEFIT") to the ELIGIBLE EMPLOYEE's surviving spouse or BENEFICIARY ("Beneficiary" shall have the same meaning as provided under the RETIREMENT PLAN):

(a) If the sum of the age and SERVICE of the ELIGIBLE EMPLOYEE at the time of death equaled 70 (69.5 or more is rounded to 70) or if the ELIGIBLE EMPLOYEE was age 55 or older at the time of death, the surviving spouse's or BENEFICIARY's benefit shall be a monthly annuity commencing at the time set forth in Section 2.01 and shall be payable for the life of the surviving spouse or BENEFICIARY. The amount of the monthly benefit shall be a monthly benefit that is actuarially equivalent to one-half of the monthly BASIC SERP BENEFIT that would have been paid to the ELIGIBLE EMPLOYEE calculated:

(i) as if he had elected to receive a BASIC SERP BENEFIT, without survivor's option; and

(ii) the monthly annuity starting date was the first of the month following the month in which the ELIGIBLE EMPLOYEE died; and

(iii) without the application of early retirement reduction factors. However, if the surviving spouse or BENEFICIARY is more than 10 years younger than the ELIGIBLE EMPLOYEE, the amount of the surviving spouse's or BENEFICIARY's benefit shall be reduced one-twentieth of 1 percent for each full month in excess of 120 months' difference in their ages, except that such reduction shall not result in a SURVIVOR'S BENEFIT lower than would have been payable if the ELIGIBLE EMPLOYEE had retired as of the date of death and elected a 50 percent joint pension with a spouse of the same gender and age as the surviving spouse or BENEFICIARY.

(b) If the ELIGIBLE EMPLOYEE is less than 55 years of age or had fewer than 70 points (as calculated under Section 3.01(a)) at the time of death, the surviving spouse or BENEFICIARY will be entitled to receive a monthly annuity commencing at the time set forth in Section 2.01. The amount of the monthly annuity payable to the surviving spouse or BENEFICIARY shall be equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the ELIGIBLE EMPLOYEE had terminated employment at the date of death, 2) had lived until age 55, 3) had begun to receive PENSION payments at age 55, and 4) had subsequently died.

(c) If a former ELIGIBLE EMPLOYEE was age 55 or older at the time of his death and not yet receiving a SERP BENEFIT under the PLAN, the surviving spouse or BENEFICIARY will be entitled to receive a monthly annuity at the time set forth in Section 2.01 in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if the former ELIGIBLE EMPLOYEE had begun receiving the converted SERP BENEFIT immediately prior to his death.

(d) If a former ELIGIBLE EMPLOYEE was younger than age 55 and had fewer than 70 points (as calculated under Section 3.01 (a)) at the time of his death, the surviving spouse or BENEFICIARY will be entitled to receive a monthly annuity at the time set forth in Section 2.01 in an amount equal to the BASIC SERP BENEFIT converted to a marital joint annuity providing for a 50 percent survivor's benefit, calculated as if: 1) the former ELIGIBLE EMPLOYEE had survived until age 55, 2) had begun receiving the converted SERP BENEFIT at age 55, and 3) had subsequently died.

3.02 A surviving spouse or BENEFICIARY who is entitled to receive a SURVIVOR'S BENEFIT under Section 3.01 shall not be entitled to receive any other benefit under the PLAN.

ARTICLE 4

ADMINISTRATIVE PROVISIONS

4.01 Administration. The PLAN shall be administered by the Senior Human Resources Officer of the CORPORATION (" PLAN ADMINISTRATOR "), who shall have the authority to interpret the PLAN and make and revise such rules as he or she deems appropriate. The PLAN ADMINISTRATOR shall have the duty and responsibility of maintaining records, making the requisite calculations, and disbursing payments hereunder. The PLAN ADMINISTRATOR's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

4.02 Amendment and Termination. The CORPORATION may amend or terminate the PLAN at any time, provided, however, that no such amendment or termination shall adversely affect an accrued benefit which an ELIGIBLE EMPLOYEE has earned prior to the date of such amendment or termination, nor shall any amendment or termination adversely affect a benefit which is being provided to an ELIGIBLE EMPLOYEE, surviving spouse, joint annuitant, or beneficiary under Article II or Article III on the date of such amendment or termination. Anything in this Section 4.02 to the contrary notwithstanding, the CORPORATION may (but is not obligated to) reduce or terminate any benefit to which an ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant, is or may become entitled provided that such ELIGIBLE EMPLOYEE, surviving spouse or joint annuitant is or becomes entitled to an amount equal to such benefit under another plan, practice, or arrangement of the CORPORATION that preserves the time and form of payment rules under the PLAN and otherwise in a manner that complies with Code Section 409A, to the extent required to not violate Code Section 409A.

4.03 Nonassignability of Benefits. Except to the extent otherwise directed by a domestic relations order that the Plan Administrator determines is a Qualified Domestic Relations Order under Section 401(a)(12) of the Internal Revenue Code, the benefits payable under this PLAN or the right to receive future benefits under this PLAN may not be anticipated, alienated, pledged, encumbered, or subject to any charge or legal process, and if any attempt is made to do so, or a person eligible for any benefits becomes bankrupt, the interest under the PLAN of the person affected may be terminated by the PLAN ADMINISTRATOR which, in its sole discretion, may cause the same to be held if applied for the benefit of one or more of the dependents of such person or make any other disposition of such benefits that it deems appropriate.

4.04 Nonguarantee of Employment. Nothing contained in this PLAN shall be construed as a contract of employment between a PARTICIPATING EMPLOYER and the ELIGIBLE EMPLOYEE, or as a right of the ELIGIBLE EMPLOYEE to be continued in the employ of a PARTICIPATING EMPLOYER, to remain as an officer of a PARTICIPATING EMPLOYER, or as a limitation on the right of a PARTICIPATING EMPLOYER to discharge any of its employees, with or without cause.

4.05 Apportionment of Costs. The costs of the PLAN may be equitably apportioned by the PLAN ADMINISTRATOR among the PARTICIPATING EMPLOYERS. Each PARTICIPATING EMPLOYER shall be responsible for making benefit payments pursuant to the PLAN on behalf of its ELIGIBLE EMPLOYEES or for reimbursing the CORPORATION for the cost of such payments, as determined by the CORPORATION in its sole discretion. In the event the respective PARTICIPATING EMPLOYER fails to make such payment or reimbursement, and the CORPORATION does not exercise its discretion to make the contribution on such PARTICIPATING EMPLOYER's behalf, future benefit accruals of the ELIGIBLE EMPLOYEES of that PARTICIPATING EMPLOYER shall be suspended. If at some future date, the PARTICIPATING EMPLOYER makes all past-due contributions, plus interest at a rate determined by the PLAN ADMINISTRATOR in his or her sole discretion, the benefit accrual of its ELIGIBLE EMPLOYEES will be recognized for the period of the suspension.

4.06 Benefits Unfunded and Unsecured. The benefits under this PLAN are unfunded, and the interest under this PLAN of any ELIGIBLE EMPLOYEE and such ELIGIBLE EMPLOYEE's right to receive a distribution of benefits under this PLAN shall be an unsecured claim against the general assets of the CORPORATION.

4.07 Applicable Law. All questions pertaining to the construction, validity, and effect of the PLAN shall be determined in accordance with the laws of the United States, and to the extent not preempted by such laws, by the laws of the State of California. The PLAN is intended to comply with the provisions of Code Section 409A. However, the CORPORATION makes no representation that the benefits provided under this PLAN will comply with Code Section 409A and makes no undertaking to prevent Code Section 409A from applying to the benefits provided under this PLAN or to mitigate its effects on any deferrals or payments made under this PLAN.

4.08 Satisfaction of Claims. Notwithstanding Section 4.05 or any other provision of the PLAN, the CORPORATION may at any time satisfy its obligations (either on a before-tax or after-tax basis) for any benefits accrued under the PLAN by the purchase from an insurance company of an annuity contract on behalf of an ELIGIBLE EMPLOYEE. Such purchase shall be in the sole discretion of the CORPORATION and shall be subject to the ELIGIBLE EMPLOYEE's acknowledgement that the CORPORATION's obligations to provide benefits hereunder have been discharged, without regard to the payments ultimately made under the contract. In the event of a purchase pursuant to this Section 4.07, the CORPORATION may in its sole discretion make payments to or on behalf of an ELIGIBLE EMPLOYEE to defray the cost to such ELIGIBLE EMPLOYEE of any personal income tax in connection with the purchase.

PG&E CORPORATION
EXECUTIVE STOCK OWNERSHIP PROGRAM

Administrative Guidelines
(As amended effective September 15, 2010)

1. Description. The Executive Stock Ownership Program (“Program”) was approved by the Nominating and Compensation Committee of the Board of Directors on October 15, 1997. The Program is an important element of the Committee’s compensation policy of aligning executive interests with those of the Corporation’s shareholders. As an integral part of the Program, the Committee also authorized the use of Special Incentive Stock Ownership Premiums (“SISOPs”) which are designed to provide incentives to Eligible Executives to assist in achieving minimum stock ownership targets established by the Committee. These Guidelines were originally adopted by the Committee on November 19, 1997, amended by the Committee on July 22, 1998, October 21, 1998, February 16, 2000, September 19, 2000, February 19, 2003, February 15, 2006, effective January 1, 2009, February 17, 2009, and September 15, 2010. As of September 15, 2010, no new officers will be eligible to earn SISOPs. As of January 1, 2011, the new PG&E Corporation 2010 Executive Stock Ownership Guidelines will be in effect, and Eligible Officers no longer will be required to meet the Targets as specified in Section 2 of this document (except to the extent those Targets apply to SISOPs). These amended Guidelines, along with the written materials provided to the Committee on October 15, 1997, describe the Program which became effective on January 1, 1998. The Program is administered by the Corporation’s Senior Human Resources Officer.
2. Eligible Executives. The Chief Executive Officer shall designate the officers of the Corporation and its affiliates who shall be Eligible Executives covered by the Program. The officers covered by the Guidelines and the applicable total stock ownership target (“Target”) are:

Officer Band	Position	Total Stock Ownership Target
1	CEO	3 × base salary
2	Heads of Business Lines, CFO, & General Counsel	2 × base salary
3	SVPs of Corp. & Utility	1.5 × base salary

3. Annual Milestones. Under the Guidelines, Targets are designed to be achieved by the end of the fifth calendar year following the calendar year in which an officer first becomes an Eligible Executive (“Target Date”). Annual Milestones have been established as a means of measuring progress towards achieving Targets and of providing incentives for Eligible Executives to expeditiously meet their Targets. The Annual Milestone at the end of the first full calendar year is 20 percent of the Target, and the Annual Milestone for each succeeding year is an additional 20 percent of the Target. Annual Milestones shall be adjusted to reflect changes in base salary;

provided, however, that in each instance any such modification shall be amortized over the remaining original five-year term. Following the Target Date, Targets also shall be modified to reflect changes in base salary.

4. Calculation of Stock Ownership Levels . Stock ownership level is the dollar value of stock and stock equivalents owned by an Eligible Executive and calculated as of the last day of the calendar year (“Measurement Date”). The purpose of this calculation is to determine the value of the stock or stock equivalents owned by the Eligible Executive as compared with the Annual Milestone or Target for that executive. For purposes of this calculation, the value per share of stock or stock equivalent (“Measurement Value”) is the average closing price of PG&E Corporation common stock as traded on the New York Stock Exchange for the last thirty (30) trading days of the year.
- a) The value of stock beneficially owned by the Eligible Executive is determined by multiplying the number of shares owned beneficially on the Measurement Date times the Measurement Value.
 - b) The value of PG&E Corporation phantom stock units credited to the Eligible Executive’s account in the PG&E Corporation Supplemental Retirement Savings Plan (“SRSP”) is determined by multiplying the number of phantom stock units credited to the Eligible Executive’s SRSP account on the Measurement Date times the Measurement Value.
 - c) The value of stock held in the PG&E Corporation stock fund of any defined contribution plan maintained by PG&E Corporation or any of its subsidiaries is determined by multiplying the number of shares in such plan on the Measurement Date times the Measurement Value.
 - d) The value of restricted stock held by the Eligible Executive is determined by multiplying the number of shares held by the Eligible Executive on the Measurement Date times the Measurement Value (for purposes of this calculation, restricted stock shall include any shares that have been approved by the Compensation Committee but not yet issued as of the Measurement Date).
 - e) The value of unvested restricted stock units held by the Eligible Executive on the Measurement Date is determined by multiplying the number of outstanding restricted stock units held by the Eligible Executive on the Measurement Date times the Measurement Value (for purposes of this calculation, restricted stock units shall include any units that have been approved by the Compensation Committee but not yet issued as of the Measurement Date).
5. Award of SISOPs . SISOPs are awarded to Eligible Executives who achieve and maintain stock ownership levels prior to the end of the third year following the year in which an officer first became an Eligible Executive. For purposes of determining awards, the total stock ownership level is calculated as set forth under paragraph 4 on the Measurement Date; however, such calculations will exclude the value of restricted stock held by the Eligible Executive as defined in paragraph 4(d) and will exclude the value of restricted stock units held by the Eligible Executive as defined in paragraph 4(e). The amount of a SISOP award shall be equal to:

- a) For the first year, 20 percent of the amount of the Eligible Executive's stock ownership level at the end of the year, up to the Annual Milestone, plus an additional 30 percent of the amount by which the stock ownership level exceeds the Annual Milestone up to the Target; and
- b) For each of the second and third years, the current stock ownership level is reduced by the stock ownership level used to calculate previous SISOP awards to determine the new ownership, then 20 percent of the amount up to the Annual Milestone by which the end of the year stock ownership level exceeds the beginning of the year stock ownership level, plus an additional 30 percent of the amount by which the end of the year balance exceeds the Annual Milestone, up to the Target.

Each time a SISOP award calculation is made, a second calculation also is made to determine the minimum number of shares which must be retained by the Eligible Executive to avoid forfeiture of the SISOP award ("Minimum Ownership Level") as discussed below in paragraph 8. This calculation converts the dollar value of the stock ownership level used as the basis for qualifying for SISOPs into a number of shares of stock by dividing that stock ownership level by the Measurement Value. Thus, for example, if an Eligible Executive's stock ownership level (less restricted stock and restricted stock units held by the Eligible Executive) was \$250,000 and the Measurement Value was \$25 per share, then the Minimum Ownership Level would be 10,000 shares.

For purposes of this calculation, the maximum share ownership level used is the Eligible Executive's Target. If an Eligible Executive has a share ownership level higher than his/her Target, the increment over the Target is not included. Thus, for example, if an Eligible Executive has a Target of \$750,000 and his/her share ownership level is \$900,000, then only \$750,000 is used to calculate the Minimum Ownership Level.

6. SISOPs Credited to the SRSP. Upon award, SISOPs are credited to the Eligible Executive's SRSP account and converted into units of phantom stock each equal in value to a share of PG&E Corporation common stock ("SISOP units") as determined in accordance with the SRSP. The SISOP units constitute "incentive awards" authorized to be awarded by the Committee to Eligible Executives under the PG&E Corporation 2006 Long-Term Incentive Plan ("2006 LTIP"). Upon credit of SISOP units to an Eligible Executive's SRSP account, an equal number of shares of PG&E Corporation common stock shall be reserved for issuance from the pool of shares authorized for issuance under the 2006 LTIP. Once a SISOP unit is credited to the Eligible Executive's SRSP account, it shall be subject to all of the terms and conditions specifically applicable to SISOP units under the SRSP. Once vested in accordance with paragraph 7 below, SISOP units are distributed in the form of an equal number of shares of PG&E Corporation common stock as provided in the SRSP.
7. Vesting. SISOPs vest only upon the expiration of three years after the date of award (provided the Eligible Executive continues to be employed on such date). An Eligible Executive's unvested SISOPs will be forfeited upon termination of employment except as otherwise provided in the Vesting Guidelines in effect on the grant date for a particular award.
8. Forfeiture of SISOP Units . So long as SISOP units remain unvested, such units are subject to forfeiture if, on each Measurement Date, the Eligible Executive's stock

ownership is less than the Minimum Ownership Level established when the SISOPs were granted (see paragraph 5). To determine forfeiture, the following steps are followed on each Measurement Date:

- a) The total stock and stock equivalents owned by an Eligible Executive is determined as set forth under paragraph 4, excluding sections 4(d) and 4(e). This total ("Current Holdings") is compared with the Minimum Ownership Level determined when the SISOPs were granted. If the Current Holdings are equal to or greater than the Minimum Ownership Level, then no unvested SISOP units are forfeited. If the Current Holdings are less than the Minimum Ownership Level, then the unvested SISOP units are forfeited in the same proportion as the Current Holdings are less than Minimum Ownership Level (for example, if the Current Holdings are 20 percent less than the Minimum Ownership Level, then 20 percent of the SISOP units are forfeited).
9. Failure to Achieve or Maintain Target . Failure to achieve stock ownership levels at Target on the Target Date, or to maintain stock ownership levels at Target on any Measurement Date thereafter, will result in the deferral into the PG&E Corporation Phantom Stock Fund of the SRSP of awards from the PG&E Corporation Long-Term Incentive Program and/or 2006 LTIP that are settled only in cash ("Cash-Settled Awards") and the Short-Term Incentive Plan ("STIP"). As of the Target Date or any Measurement Date, to the extent that stock ownership levels are below Target, the Cash-Settled Award or STIP award (in an amount determined by PG&E Corporation in its sole discretion) shall be converted into phantom stock units, to the extent necessary to achieve the Target stock ownership level. Such conversion of Cash-Settled Awards and STIP awards shall continue for successive Measurement Dates, if necessary, until Target is met. Phantom stock units attributable to Cash-Settled Awards and STIP awards described in this paragraph 9 will be paid from the SRSP in a lump sum in accordance with Section 7(a) of the SRSP. Notwithstanding anything to the contrary set forth in this Section 9, the deferral provisions of this Section 9 shall be applied only with respect to Cash-Settled Awards and STIP awards that can be deferred in accordance with the initial deferral election rules of Section 409A of the Internal Revenue Code of 1986 determined as if the Eligible Executive had made a deferral election on the Target Date or Measurement Date, as applicable, and the Eligible Executive shall be deemed to have made the election hereunder on the applicable Target Date or Measurement Date by failing to achieve the applicable stock ownership levels.

PG&E CORPORATION
2010 EXECUTIVE STOCK OWNERSHIP GUIDELINES

(As adopted effective January 1, 2011)

1. Description. The 2010 Executive Stock Ownership Guidelines (“Guidelines”) was approved by the Compensation Committee of the PG&E Corporation Board of Directors effective January 1, 2011. The Guidelines are an important element of the Committee’s compensation policy of aligning executive interests with those of the Corporation’s shareholders. The Guidelines are administered by the PG&E Corporation Senior Human Resources Officer.
2. Ownership Targets. The applicable total stock ownership targets (“Target”) are:

Officer Band	Position	Total Stock Ownership Target
1	Chairman, CEO and President, PG&E Corporation	6× base salary
2	President, Pacific Gas and Electric Company SVP and Chief Operating Officer SVP and Chief Financial Officer SVP, Corporate Strategy and Development SVP and General Counsel	3× base salary
3	SVPs of PG&E Corporation and Pacific Gas and Electric Company (Utility)	1.5× base salary

Conformance with the applicable Targets will be determined as of December 31 of each calendar year (“Measurement Date”). Targets will be based on base salary in effect on the Measurement Date.

3. Retention Ratio. Under the Guidelines, Officers are expected to hold 50 percent of their net shares realized from options exercises or stock or stock unit vesting, after withholding for the exercise price and taxes, until the applicable Target is met.
4. Calculation of Stock Ownership Levels. The value of the stock or stock equivalents owned by the Eligible Executive, as of the Measurement Date, is based on the average closing price of PG&E Corporation common stock as traded on the New

York Stock Exchange for the last thirty (30) trading days of the year, ("Measurement Value").

- a) The value of stock beneficially owned by the Eligible Executive is determined by multiplying the number of shares owned beneficially on the Measurement Date times the Measurement Value.
- b) The value of PG&E Corporation phantom stock units credited to the Eligible Executive's account in the PG&E Corporation Supplemental Retirement Savings Plan ("SRSP") is determined by multiplying the number of phantom stock units in the Eligible Executive's SRSP account on the Measurement Date times the Measurement Value.
- c) The value of stock held in the PG&E Corporation stock fund of any defined contribution plan maintained by PG&E Corporation or any of its subsidiaries is determined by multiplying the number of shares in such fund on the Measurement Date times the Measurement Value.
- d) The value of unvested restricted stock and/or restricted stock units held by an Eligible Executive is determined by multiplying the number of shares that the Eligible Executive would be entitled to receive if the Eligible Executive voluntarily terminated his or her employment on the Measurement Date.

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

	Three Months Ended September 30, 2010	Nine Months Ended September 30, 2010	Year Ended December 31,				
			2009	2008	2007	2006	2005
Earnings:							
Net income	\$ 265	\$ 868	\$1,250	\$1,199	\$1,024	\$ 985	\$ 934
Income taxes provision	107	498	482	488	571	602	574
Net fixed charges	199	588	817	860	889	801	589
Total Earnings	<u>\$ 571</u>	<u>\$ 1,954</u>	<u>\$2,549</u>	<u>\$2,547</u>	<u>\$2,484</u>	<u>\$2,388</u>	<u>\$2,097</u>
Fixed Charges:							
Interest on short-term borrowings and long-term debt, net	\$ 181	\$ 535	\$ 754	\$ 794	\$ 834	\$ 770	\$ 573
Interest on capital leases	4	13	19	22	23	11	1
AFUDC debt	14	40	44	44	32	20	15
Total Fixed Charges	<u>\$ 199</u>	<u>\$ 588</u>	<u>\$ 817</u>	<u>\$ 860</u>	<u>\$ 889</u>	<u>\$ 801</u>	<u>\$ 589</u>
Ratios of Earnings to							
Fixed Charges	<u>2.87</u>	<u>3.32</u>	<u>3.12</u>	<u>2.96</u>	<u>2.79</u>	<u>2.98</u>	<u>3.56</u>

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 September 30, 2010	Nine Months Ended September 30, 2010	Year Ended December 31,				
			2009	2008	2007	2006	2005
Earnings:							
Net income	\$ 265	\$ 868	\$1,250	\$1,199	\$1,024	\$ 985	\$ 934
Income taxes provision	107	498	482	488	571	602	574
Net fixed charges	199	588	817	860	889	801	589
Total Earnings	<u>\$ 571</u>	<u>\$ 1,954</u>	<u>\$2,549</u>	<u>\$2,547</u>	<u>\$2,484</u>	<u>\$2,388</u>	<u>\$2,097</u>
Fixed Charges:							
Interest on short-term borrowings and long-term debt, net	\$ 181	\$ 535	\$ 754	\$ 794	\$ 834	\$ 770	\$ 573
Interest on capital leases	4	13	19	22	23	11	1
AFUDC debt	14	40	44	44	32	20	15
Earnings required to cover the preferred stock dividend	—	—	—	—	—	—	—
Total Fixed Charges	<u>\$ 199</u>	<u>\$ 588</u>	<u>\$ 817</u>	<u>\$ 860</u>	<u>\$ 889</u>	<u>\$ 801</u>	<u>\$ 589</u>
Preferred Stock Dividends:							
Tax deductible dividends	2	7	9	9	9	12	9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	1	5	7	7	8	3	12
Total Preferred Stock Dividends	<u>3</u>	<u>12</u>	<u>16</u>	<u>16</u>	<u>17</u>	<u>15</u>	<u>21</u>
Total Combined Fixed Charges and Preferred Stock Dividends	<u>\$ 202</u>	<u>\$ 600</u>	<u>\$ 833</u>	<u>\$ 876</u>	<u>\$ 906</u>	<u>\$ 816</u>	<u>\$ 610</u>
Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends	<u>2.83</u>	<u>3.26</u>	<u>3.06</u>	<u>2.91</u>	<u>2.74</u>	<u>2.93</u>	<u>3.44</u>

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		Year Ended December 31,				
	Ended September 30, 2010	Nine Months Ended September 30, 2010	2009	2008	2007	2006	2005
Earnings:							
Net income	\$ 261	\$ 859	\$1,234	\$1,198	\$1,020	\$1,005	\$ 920
Income taxes provision	107	479	460	425	539	554	544
Fixed charges	208	630	877	907	937	845	639
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	(3)	(12)	(16)	(16)	(17)	(15)	(20)
Total Earnings	<u>\$ 573</u>	<u>\$ 1,956</u>	<u>\$2,555</u>	<u>\$2,514</u>	<u>\$2,479</u>	<u>\$2,389</u>	<u>\$2,083</u>
Fixed Charges:							
Interest and amortization of premiums, discounts and capitalized expenses related to short-term borrowings and long-term debt, net	\$ 187	\$ 565	\$ 798	\$ 825	\$ 865	\$ 799	\$ 603
Interest on capital leases	4	13	19	22	23	11	1
AFUDC debt	14	40	44	44	32	20	15
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	3	12	16	16	17	15	20
Total Fixed Charges	<u>\$ 208</u>	<u>\$ 630</u>	<u>\$ 877</u>	<u>\$ 907</u>	<u>\$ 937</u>	<u>\$ 845</u>	<u>\$ 639</u>
Ratios of Earnings to Fixed Charges	<u>2.75</u>	<u>3.10</u>	<u>2.91</u>	<u>2.77</u>	<u>2.65</u>	<u>2.83</u>	<u>3.26</u>

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, Peter A. Darbee, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 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: November 4, 2010

PETER A. DARBEE

Peter A. Darbee

Chairman, Chief Executive Officer, and President

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

I, Kent M. Harvey, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 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: November 4, 2010

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 September 30, 2010 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: November 4, 2010

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 September 30, 2010 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: November 4, 2010

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 September 30, 2010 ("Form 10-Q"), I, Peter A. Darbee, Chairman, Chief Executive Officer, and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

- (1) 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.

PETER A. DARBEE

PETER A. DARBEE

Chairman, Chief Executive Officer, and
President

November 4, 2010

**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 September 30, 2010 ("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

November 4, 2010

**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 September 30, 2010 ("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

November 4, 2010

**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 September 30, 2010 ("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

November 4, 2010