PG&E CORP

FORM 10-Q
(Quarterly Report)

Filed 07/31/14 for the Period Ending 06/30/14

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

(Mark One)

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

For the quarterly period ended June 30, 2014

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 77 Beale Street P.O. Box 770000 San Francisco, California 94177

Address of principal executive offices, including zip code

Pacific Gas and Electric Company (415) 973-7000	PG&E Corporation (415) 973-1000

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. [X] 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:	[X] Yes [ ] No
Pacific Gas and Electric Company:	[X] 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:	[X] Large accelerated filer	[ ] Accelerated filer
	[ ] Non-accelerated filer	[ ] Smaller reporting company
Pacific Gas and Electric Company:	[ ] Large accelerated filer	[ ] Accelerated filer
	[X] 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 [X] No
Pacific Gas and Electric Company:	[ ] Yes [X] No

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

Common stock outstanding as of July 22, 2014:

PG&E Corporation:	471,411,575
Pacific Gas and Electric Company:	264,374,809

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2014

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GLOSSARY

The following terms and abbreviations appearing in the text of this report have the meanings indicated below.

2013 Annual Report	PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2013
AFUDC	allowance for funds used during construction
ALJ	administrative law judge
CAISO	California Independent System Operator
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
EPA	Environmental Protection Agency
EPS	earnings per common share
FERC	Federal Energy Regulatory Commission
GAAP	generally accepted accounting principles
GHG	greenhouse gas
GRC	general rate case
GT&S	gas transmission and storage
IRS	Internal Revenue Service
NEIL	Nuclear Electric Insurance Limited
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
ORA	Office of Ratepayer Advocates
PSEP	pipeline safety enhancement plan
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
VIE(s)	variable interest entity(ies)

PART I. FINANCIAL INFORMATION
ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	**2014**	**2013**	**2014**	**2013**
Operating Revenues				
Electric	$ 3,233	$ 3,059	$ 6,234	$ 5,858
Natural gas	719	717	1,609	1,590
Total operating revenues	**3,952**	**3,776**	**7,843**	**7,448**
Operating Expenses				
Cost of electricity	1,349	1,189	2,559	2,172
Cost of natural gas	200	179	560	525
Operating and maintenance	1,328	1,256	2,627	2,594
Depreciation, amortization, and decommissioning	557	516	1,095	1,019
Total operating expenses	**3,434**	**3,140**	**6,841**	**6,310**
Operating Income	**518**	**636**	**1,002**	**1,138**
Interest income	2	2	5	4
Interest expense	(188)	(177)	(373)	(353)
Other income, net	43	24	62	52
Income Before Income Taxes	**375**	**485**	**696**	**841**
Income tax provision	104	153	195	267
Net Income	**271**	**332**	**501**	**574**
Preferred stock dividend requirement of subsidiary	4	4	7	7
Income Available for Common Shareholders	**$ 267**	**$ 328**	**$ 494**	**$ 567**
Weighted Average Common Shares Outstanding, Basic	**467**	**442**	**463**	**438**
Weighted Average Common Shares Outstanding, Diluted	**469**	**443**	**465**	**439**
Net Earnings Per Common Share, Basic	**$ 0.57**	**$ 0.74**	**$ 1.07**	**$ 1.29**
Net Earnings Per Common Share, Diluted	**$ 0.57**	**$ 0.74**	**$ 1.06**	**$ 1.29**
Dividends Declared Per Common Share	**$ 0.46**	**$ 0.46**	**$ 0.91**	**$ 0.91**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2014	2013	2014	2013
Net Income	$ 271	$ 332	$ 501	$ 574
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations (net of taxes of $0, $3, $0 and $6, at respective dates)	-	4	-	8
Net change in investments (net of taxes of $7, $11, $3, $15 at respective dates)	(11)	16	(6)	22
Total other comprehensive income (loss)	(11)	20	(6)	30
Comprehensive Income	260	352	495	604
Preferred stock dividend requirement of subsidiary	4	4	7	7
Comprehensive Income Attributable to Common Shareholders	$ 256	$ 348	$ 488	$ 597

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	June 30, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and cash equivalents	$ 132	$ 296
Restricted cash	299	301
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $68 and $80 at respective dates)	1,009	1,091
Accrued unbilled revenue	870	766
Regulatory balancing accounts	1,745	1,124
Other	304	312
Regulatory assets	404	448
Inventories:		
Gas stored underground and fuel oil	141	137
Materials and supplies	320	317
Income taxes receivable	613	574
Other	360	611
Total current assets	**6,197**	**5,977**
Property, Plant, and Equipment		
Electric	43,990	42,881
Gas	15,040	14,379
Construction work in progress	1,981	1,834
Other	2	2
Total property, plant, and equipment	**61,013**	**59,096**
Accumulated depreciation	(18,530)	(17,844)
Net property, plant, and equipment	**42,483**	**41,252**
Other Noncurrent Assets		
Regulatory assets	4,821	4,913
Nuclear decommissioning trusts	2,428	2,342
Income taxes receivable	88	85
Other	1,008	1,036
Total other noncurrent assets	**8,345**	**8,376**
TOTAL ASSETS	**$ 57,025**	**$ 55,605**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions, except share amounts)	June 30, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 1,452	$ 1,174
Long-term debt, classified as current	-	889
Accounts payable:		
Trade creditors	1,161	1,293
Disputed claims and customer refunds	86	154
Regulatory balancing accounts	1,069	1,008
Other	472	471
Interest payable	865	892
Other	1,544	1,612
Total current liabilities	**6,649**	**7,493**
Noncurrent Liabilities		
Long-term debt	13,966	12,717
Regulatory liabilities	5,966	5,660
Pension and other postretirement benefits	1,578	1,601
Asset retirement obligations	3,561	3,539
Deferred income taxes	7,874	7,823
Other	2,151	2,178
Total noncurrent liabilities	**35,096**	**33,518**
Commitments and Contingencies (Note 10)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares, 470,950,685 and 456,670,424 shares outstanding at respective dates	10,176	9,550
Reinvested earnings	4,808	4,742
Accumulated other comprehensive income	44	50
Total shareholders' equity	**15,028**	**14,342**
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	**15,280**	**14,594**
TOTAL LIABILITIES AND EQUITY	**$ 57,025**	**$ 55,605**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited)	
	Six Months Ended June 30,	
(in millions)	2014	2013
Cash Flows from Operating Activities		
Net income	$ 501	$ 574
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,095	1,019
Allowance for equity funds used during construction	(46)	(52)
Deferred income taxes and tax credits, net	51	346
Other	139	157
Effect of changes in operating assets and liabilities:		
Accounts receivable	(30)	(22)
Inventories	(7)	(31)
Accounts payable	(101)	28
Income taxes receivable/payable	(39)	(143)
Other current assets and liabilities	94	(367)
Regulatory assets, liabilities, and balancing accounts, net	(311)	(192)
Other noncurrent assets and liabilities	(66)	142
Net cash provided by operating activities	**1,280**	**1,459**
Cash Flows from Investing Activities		
Capital expenditures	(2,320)	(2,521)
Decrease in restricted cash	2	25
Proceeds from sales and maturities of nuclear decommissioning trust investments	877	795
Purchases of nuclear decommissioning trust investments	(873)	(786)
Other	21	16
Net cash used in investing activities	**(2,293)**	**(2,471)**
Cash Flows from Financing Activities		
Borrowings (repayments) under revolving credit facilities	(260)	140
Net issuances of commercial paper, net of discount of $1 at respective dates	237	321
Proceeds from issuance of short-term debt, net of issuance costs	300	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $14 and $8 at respective dates	1,236	742
Repayments of long-term debt	(889)	(461)
Common stock issued	589	562
Common stock dividends paid	(408)	(386)
Other	44	(26)
Net cash provided by financing activities	**849**	**892**
Net change in cash and cash equivalents	**(164)**	**(120)**
Cash and cash equivalents at January 1	**296**	**401**
Cash and cash equivalents at June 30	**$ 132**	**$ 281**
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest, net of amounts capitalized	$ (318)	$ (312)
Income taxes, net	(1)	(65)
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	$ 215	$ 202
Capital expenditures financed through accounts payable	224	253
Noncash common stock issuances	10	11
Terminated capital leases	68	-

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2014**	**2013**	**2014**	**2013**
Operating Revenues				
Electric	$ 3,232	$ 3,057	$ 6,232	$ 5,855
Natural gas	719	718	1,609	1,591
Total operating revenues	**3,951**	**3,775**	**7,841**	**7,446**
Operating Expenses				
Cost of electricity	1,349	1,189	2,559	2,172
Cost of natural gas	200	179	560	525
Operating and maintenance	1,321	1,256	2,618	2,592
Depreciation, amortization, and decommissioning	556	516	1,094	1,019
Total operating expenses	**3,426**	**3,140**	**6,831**	**6,308**
Operating Income	**525**	**635**	**1,010**	**1,138**
Interest income	3	3	5	4
Interest expense	(185)	(171)	(364)	(341)
Other income, net	17	22	37	46
Income Before Income Taxes	**360**	**489**	**688**	**847**
Income tax provision	110	160	210	281
Net Income	**250**	**329**	**478**	**566**
Preferred stock dividend requirement	4	4	7	7
Income Available for Common Stock	**$ 246**	**$ 325**	**$ 471**	**$ 559**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2014**	**2013**	**2014**	**2013**
Net Income	**$ 250**	**$ 329**	**$ 478**	**$ 566**
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations (net of taxes of $0, $3, $0 and $6 at respective dates)	-	4	-	9
Total other comprehensive income	**-**	**4**	**-**	**9**
Comprehensive Income	**$ 250**	**$ 333**	**$ 478**	**$ 575**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	June 30, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and cash equivalents	$ 70	$ 65
Restricted cash	299	301
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $68 and $80 at respective dates)	1,009	1,091
Accrued unbilled revenue	870	766
Regulatory balancing accounts	1,745	1,124
Other	306	313
Regulatory assets	404	448
Inventories:		
Gas stored underground and fuel oil	141	137
Materials and supplies	320	317
Income taxes receivable	598	563
Other	208	523
Total current assets	**5,970**	**5,648**
Property, Plant, and Equipment		
Electric	43,990	42,881
Gas	15,040	14,379
Construction work in progress	1,981	1,834
Total property, plant, and equipment	**61,011**	**59,094**
Accumulated depreciation	(18,529)	(17,843)
Net property, plant, and equipment	**42,482**	**41,251**
Other Noncurrent Assets		
Regulatory assets	4,821	4,913
Nuclear decommissioning trusts	2,428	2,342
Income taxes receivable	83	81
Other	824	814
Total other noncurrent assets	**8,156**	**8,150**
TOTAL ASSETS	**$ 56,608**	**$ 55,049**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions, except share amounts)	June 30, 2014	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 1,340	$ 914
Long-term debt, classified as current	-	539
Accounts payable:		
Trade creditors	1,161	1,293
Disputed claims and customer refunds	86	154
Regulatory balancing accounts	1,069	1,008
Other	462	432
Interest payable	862	887
Other	1,285	1,382
Total current liabilities	**6,265**	**6,609**
Noncurrent Liabilities		
Long-term debt	13,616	12,717
Regulatory liabilities	5,966	5,660
Pension and other postretirement benefits	1,505	1,530
Asset retirement obligations	3,561	3,539
Deferred income taxes	8,060	8,042
Other	2,106	2,111
Total noncurrent liabilities	**34,814**	**33,599**
Commitments and Contingencies (Note 10)		
Shareholders' Equity		
Preferred stock	258	258
Common stock, $5 par value, authorized 800,000,000 shares, 264,374,809 shares outstanding at respective dates	1,322	1,322
Additional paid-in capital	6,396	5,821
Reinvested earnings	7,540	7,427
Accumulated other comprehensive income	13	13
Total shareholders' equity	**15,529**	**14,841**
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**$ 56,608**	**$ 55,049**

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited)	
	Six Months Ended June 30,	
(in millions)	**2014**	**2013**
Cash Flows from Operating Activities		
Net income	$ 478	$ 566
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,094	1,019
Allowance for equity funds used during construction	(46)	(52)
Deferred income taxes and tax credits, net	18	337
Other	108	126
Effect of changes in operating assets and liabilities:		
Accounts receivable	(31)	(24)
Inventories	(7)	(31)
Accounts payable	(72)	68
Income taxes receivable/payable	(35)	(162)
Other current assets and liabilities	141	(317)
Regulatory assets, liabilities, and balancing accounts, net	(311)	(192)
Other noncurrent assets and liabilities	(76)	126
Net cash provided by operating activities	**1,261**	**1,464**
Cash Flows from Investing Activities		
Capital expenditures	(2,320)	(2,521)
Decrease in restricted cash	2	25
Proceeds from sales and maturities of nuclear decommissioning trust investments	877	795
Purchases of nuclear decommissioning trust investments	(873)	(786)
Other	17	8
Net cash used in investing activities	**(2,297)**	**(2,479)**
Cash Flows from Financing Activities		
Net issuances of commercial paper, net of discount of $1 at respective dates	125	321
Proceeds from issuance of short-term debt, net of issuance costs	300	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $11 and $8 at respective dates	889	742
Repayments of long-term debt	(539)	(461)
Preferred stock dividends paid	(7)	(7)
Common stock dividends paid	(358)	(358)
Equity contribution	580	665
Other	51	(20)
Net cash provided by financing activities	**1,041**	**882**
Net change in cash and cash equivalents	**5**	**(133)**
Cash and cash equivalents at January 1	**65**	**194**
Cash and cash equivalents at June 30	**$ 70**	**$ 61**
Supplemental disclosures of cash flow information		
Cash paid for:		
Interest, net of amounts capitalized	$ (307)	$ (300)
Income taxes, net	(1)	(86)
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$ 224	$ 253
Terminated capital leases	68	-

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 operating subsidiary is Pacific Gas and Electric Company, 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 primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This quarterly report on Form 10-Q is a combined report of PG&E Corporation and the Utility. PG&E Corporation's Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and subsidiaries. The Utility's Condensed Consolidated Financial Statements include the accounts of the Utility and its subsidiaries. All intercompany balances and transactions have been eliminated. The Notes to the Condensed Consolidated Financial Statements apply to both PG&E Corporation and the Utility unless described otherwise. PG&E Corporation and the Utility operate in one segment.

The accompanying Condensed Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the interim period reporting requirements of Form 10-Q and reflect all adjustments (consisting only of normal recurring adjustments) that management believes are necessary for the fair presentation of PG&E Corporation and the Utility's financial condition, results of operations, and cash flows for the periods presented. The information at December 31, 2013 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in the 2013 Annual Report. This quarterly report should be read in conjunction with the 2013 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, legal and regulatory contingencies, environmental remediation liabilities, asset retirement obligations, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Condensed Consolidated Financial Statements are appropriate and reasonable. Actual results could differ materially from those estimates.

NOTE 2: SIGNIFICANT ACCOUNTING POLICIES

The significant accounting policies used by PG&E Corporation and the Utility are discussed in Note 2 of the Notes to the Consolidated Financial Statements in the 2013 Annual Report.

Variable Interest Entities

A VIE is an entity that 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 that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at June 30, 2014, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at June 30, 2014, it did not consolidate any of them.

PG&E Corporation affiliates have entered into four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that are considered VIEs. Under these agreements, PG&E Corporation has made cumulative lease payments and investment contributions of $363 million to these companies since 2010 in exchange for the right to receive benefits from local rebates, federal grants, and a share of the customer payments made to these companies. At June 30, 2014 and December 31, 2013, the carrying amount of PG&E Corporation's investment in these VIEs was $87 million and $98 million, respectively. PG&E Corporation does not have decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs, such as the design of the companies, vendor selection, construction, and the ongoing operations of the companies. Since PG&E Corporation was not the primary beneficiary of any of these VIEs at June 30, 2014, it did not consolidate any of them. On July 2, 2014, PG&E Corporation disposed of its interest in the tax equity agreements. PG&E Corporation has no remaining commitment to fund these agreements.

Pension and Other Postretirement Benefits

PG&E Corporation and the Utility provide a non-contributory defined benefit pension plan for eligible employees, as well as contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees.

The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Financial Statements for the three and six months ended June 30, 2014 and 2013 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
(in millions)	**2014**	**2013**	**2014**	**2013**
Service cost for benefits earned	$ 96	$ 115	$ 11	$ 13
Interest cost	173	156	19	18
Expected return on plan assets	(201)	(163)	(26)	(20)
Amortization of prior service cost	5	5	5	5
Amortization of net actuarial loss	1	28	1	2
Net periodic benefit cost	**74**	**141**	**10**	**18**
Less: transfer to regulatory account [1]	9	(56)	-	-
Total	**$ 83**	**$ 85**	**$ 10**	**$ 18**

[1] The Utility recorded these amounts to a regulatory account since they are probable of recovery from customers in future rates.

	Pension Benefits		Other Benefits	
	Six Months Ended June 30,			
(in millions)	**2014**	**2013**	**2014**	**2013**
Service cost for benefits earned	$ 195	$ 230	$ 22	$ 26
Interest cost	346	312	38	37
Expected return on plan assets	(403)	(325)	(52)	(40)
Amortization of prior service cost	10	10	11	11
Amortization of net actuarial loss	1	55	1	3
Net periodic benefit cost	**149**	**282**	**20**	**37**
Less: transfer to regulatory account [1]	19	(113)	-	-
Total	**$ 168**	**$ 169**	**$ 20**	**$ 37**

[1] The Utility recorded these amounts to a regulatory account since they are probable of recovery from customers in future rates.

There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) are summarized below:

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
	Three Months Ended June 30, 2014			
Beginning balance	$ (7)	$ 15	$ 47	$ 55
Other comprehensive income before reclassifications:				
Gain on investments (net of taxes of $0, $0, and $3, respectively)	-	-	5	5
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (net of taxes of $2, $2, and $0, respectively) (1)	3	3	-	6
Amortization of net actuarial loss (net of taxes of $0, $0, and $0, respectively) (1)	1	1	-	2
Transfer to regulatory account (net of taxes of $2, $2, and $0, respectively) (1)	(4)	(4)	-	(8)
Realized gain on investments (net of taxes of $0, $0, and $10, respectively)	-	-	(16)	(16)
Net current period other comprehensive loss	**-**	**-**	**(11)**	**(11)**
Ending balance	**$ (7)**	**$ 15**	**$ 36**	**$ 44**

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
	Three Months Ended June 30, 2013			
Beginning balance	$ (28)	$ (73)	$ 10	$ (91)
Other comprehensive income before reclassifications:				
Gain on investments (net of taxes of $0, $0, and $11, respectively)	-	-	16	16
Amounts reclassified from other comprehensive income: (1)				
Amortization of prior service cost (net of taxes of $2, $2, and $0, respectively)	3	3	-	6
Amortization of net actuarial loss (net of taxes of $12, $1, and $0, respectively)	16	1	-	17
Transfer to regulatory account (net of taxes of $13, $0, and $0, respectively)	(19)	-	-	(19)
Net current period other comprehensive income	**-**	**4**	**16**	**20**
Ending balance	**$ (28)**	**$ (69)**	**$ 26**	**$ (71)**

(1) These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
	Six Months Ended June 30, 2014			
Beginning balance	$ (7)	$ 15	$ 42	$ 50
Other comprehensive income before reclassifications:				
Gain on investments (net of taxes of $0, $0, and $7, respectively)	-	-	10	10
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (net of taxes of $4, $4, and $0, respectively) [1]	6	7	-	13
Amortization of net actuarial loss (net of taxes of $0, $0, and $0, respectively) [1]	1	1	-	2
Transfer to regulatory account (net of taxes of $4, $4, and $0, respectively) [1]	(7)	(8)	-	(15)
Realized gain on investments (net of taxes of $0, $0, and $10, respectively)	-	-	(16)	(16)
Net current period other comprehensive loss	**-**	**-**	**(6)**	**(6)**
Ending balance	**$ (7)**	**$ 15**	**$ 36**	**$ 44**

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
	Six Months Ended June 30, 2013			
Beginning balance	$ (28)	$ (77)	$ 4	$ (101)
Other comprehensive income before reclassifications:				
Gain on investments (net of taxes of $0, $0, and $15, respectively)	-	-	22	22
Amounts reclassified from other comprehensive income: [1]				
Amortization of prior service cost (net of taxes of $4, $5, and $0, respectively)	6	6	-	12
Amortization of net actuarial loss (net of taxes of $23, $1, and $0, respectively)	32	2	-	34
Transfer to regulatory account (net of taxes of $26, $0, and $0, respectively)	(38)	-	-	(38)
Net current period other comprehensive income	**-**	**8**	**22**	**30**
Ending balance	**$ (28)**	**$ (69)**	**$ 26**	**$ (71)**

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See the "Pension and Other Postretirement Benefits" table above for additional details.)

There was no material difference between PG&E Corporation and the Utility for the information disclosed above, with the exception of other investments which are held by PG&E Corporation.

Accounting Standards Issued But Not Yet Adopted

Revenue Recognition Standard

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers*, which amends existing revenue recognition guidance . The accounting standards update will be effective on January 1, 2017. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are composed of the following:

	Balance at	
(in millions)	**June 30, 2014**	**December 31, 2013**
Pension benefits	$ 1,415	$ 1,444
Deferred income taxes	1,932	1,835
Utility retained generation	479	503
Environmental compliance costs	599	628
Price risk management	83	106
Electromechanical meters	103	135
Unamortized loss, net of gain, on reacquired debt	124	135
Other	86	127
Total long-term regulatory assets	**$ 4,821**	**$ 4,913**

Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

	Balance at	
(in millions)	**June 30, 2014**	**December 31, 2013**
Cost of removal obligations	$ 3,978	$ 3,844
Recoveries in excess of asset retirement obligations	754	748
Public purpose programs	677	587
Other	557	481
Total long-term regulatory liabilities	**$ 5,966**	**$ 5,660**

Regulatory Balancing Accounts

The Utility's recovery of revenue requirements and costs is generally decoupled from the volume of sales. The Utility records (1) differences between the Utility's authorized revenue requirement and actual customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility does not expect to collect or refund over the next 12 months are included in other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Condensed Consolidated Balance Sheets.

The Utility sells and delivers electricity and natural gas. The Utility also administers public purpose programs, primarily related to customer energy efficiency programs. The balancing accounts associated with these items will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

Current regulatory balancing accounts receivable and payable are composed of the following:

(in millions)	Receivable Balance at June 30, 2014	Receivable Balance at December 31, 2013
Electric distribution	$ 455	$ 102
Utility generation	257	57
Gas distribution	154	70
Energy procurement	486	410
Public purpose programs	39	56
Other	354	429
Total regulatory balancing accounts receivable	**$ 1,745**	**$ 1,124**

(in millions)	Payable Balance at June 30, 2014	Payable Balance at December 31, 2013
Energy procurement	$ 298	$ 298
Public purpose programs	199	171
Other	572	539
Total regulatory balancing accounts payable	**$ 1,069**	**$ 1,008**

NOTE 4: DEBT

Senior Notes

In February 2014, the Utility issued $450 million principal amount of 3.75% Senior Notes due February 15, 2024 and $450 million principal amount of 4.75% Senior Notes due February 15, 2044. The proceeds were used to repay the 4.80% Senior Notes, in the principal outstanding amount of $539 million, to fund capital expenditures, and for general corporate purposes. In addition, in May 2014, the Utility issued $300 million principal amount of Floating Rate Senior Notes due May 11, 2015. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

In February 2014, PG&E Corporation issued $350 million principal amount of 2.40% Senior Notes due March 1, 2019. The proceeds were used to repay the 5.75% Senior Notes, in the principal outstanding amount of $350 million.

Revolving Credit Facilities and Commercial Paper Program

In April 2014, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 1, 2018 to April 1, 2019. PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $1.75 billion, respectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities.

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings at June 30, 2014:

(in millions)	Termination Date	Facility Limit	Letters of Credit Outstanding	Borrowings	Commercial Paper	Facility Availability
PG&E Corporation	April 2019	$ 300 (1)	$ -	$ -	$ 112	$ 188
Utility	April 2019	3,000 (2)	86	$ -	1,041	1,873
Total revolving credit facilities		**$ 3,300**	**$ 86**	**$ -**	**$ 1,153**	**$ 2,061**

(1) Includes a $100 million sublimit for letters of credit and a $100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.
(2) Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

Pollution Control Bonds

At June 30, 2014, the interest rates on the $614 million principal amount of pollution control bonds Series 1996 C, E, F, and 1997 B and the related loan agreements ranged from 0.01% to 0.04%. At June 30, 2014, the interest rates on the $309 million principal amount of pollution control bonds Series 2009 A-D and the related loan agreements ranged from 0.01% to 0.04%.

NOTE 5: EQUITY

PG&E Corporation's and the Utility's changes in equity for the six months ended June 30, 2014 were as follows:

	PG&E Corporation	Utility
(in millions)	**Total Equity**	**Total Shareholders' Equity**
Balance at December 31, 2013	**$ 14,594**	**$ 14,841**
Comprehensive income	495	478
Equity contributions	-	580
Common stock issued	599	-
Share-based compensation	27	(5)
Common stock dividends declared	(428)	(358)
Preferred stock dividend requirement	-	(7)
Preferred stock dividend requirement of subsidiary	(7)	-
Balance at June 30, 2014	**$ 15,280**	**$ 15,529**

In February 2014, PG&E Corporation entered into a new equity distribution agreement providing for the sale of PG&E Corporation common stock having an aggregate gross sales price of up to $500 million.

PG&E Corporation issued common stock in the following transactions:

- During the six months ended June 30, 2014, 4 million shares were issued for cash proceeds of $160 million under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans; and

- During the three and six months ended June 30, 2014, PG&E Corporation sold 5 and 10 million shares under the February 2014 equity distribution agreement for cash proceeds of $206 and $429 million, net of commissions paid of $2 and $4 million, respectively.

NOTE 6: EARNINGS PER SHARE

PG&E Corporation's basic EPS is calculated by dividing the income available for common shareholders by the weighted average number of common shares outstanding. PG&E Corporation applies the treasury stock method of reflecting the dilutive effect of outstanding share-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 common shares outstanding for calculating diluted EPS:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	**2014**	**2013**	**2014**	**2013**
Income available for common shareholders	$ 267	$ 328	$ 494	$ 567
Weighted average common shares outstanding, basic	467	442	463	438
Add incremental shares from assumed conversions:				
Employee share-based compensation	2	1	2	1
Weighted average common share outstanding, diluted	469	443	465	439
Total earnings per common share, diluted	**$ 0.57**	**$ 0.74**	**$ 1.06**	**$ 1.29**

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

NOTE 7: DERIVATIVES

The Utility uses both derivative and non-derivative contracts in managing its customers' exposure to commodity-related price risk, including forward contracts, swap agreements, futures contracts, and option contracts.

These instruments are not held for speculative purposes and are subject to certain regulatory requirements. Customer rates are designed to recover the Utility's reasonable costs of providing services, including the costs related to price risk management activities.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Condensed Consolidated Balance Sheets. The Utility expects to fully recover in rates all costs related to derivatives as long as the current ratemaking mechanism remains in place and the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities. (See Note 3 above.) Net realized gains or losses on commodity derivatives 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 or refund to customers.

The Utility offsets cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement where the right of offset and the intention to offset exist.

The Utility elects the normal purchase and sale exception for eligible derivatives. Derivatives that require 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 derivatives that are eligible for the normal purchase and sales exception are not reflected in the Condensed Consolidated Balance Sheets at fair value, but are accounted for under the accrual method of accounting. Therefore, expenses are recognized as incurred.

Volume of Derivative Activity

At June 30, 2014, the volumes of the Utility's outstanding derivatives were as follows:

		Contract Volume (1)			
Underlying Product	**Instruments**	**Less Than 1 Year**	**1 Year or Greater but Less Than 3 Years**	**3 Years or Greater but Less Than 5 Years**	**5 Years or Greater (2)**
Natural Gas (3) (MMBtus (4))	Forwards and Swaps	253,455,503	68,107,500	5,370,000	-
	Options	118,345,529	56,101,311	1,800,000	-
Electricity (Megawatt-hours)	Forwards and Swaps	1,750,584	1,956,498	1,735,012	1,200,183
	Congestion Revenue Rights	60,291,148	86,200,035	50,662,422	25,365,949

(1) Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.
(2) Derivatives in this category expire between 2019 and 2023.
(3) Amounts shown are for the combined positions of the electric fuels and core gas portfolios.
(4) Million British Thermal Units.

At December 31, 2013, the volumes of the Utility's outstanding derivatives were as follows:

		Contract Volume [1]			
Underlying Product	**Instruments**	**Less Than 1 Year**	**1 Year or Greater but Less Than 3 Years**	**3 Years or Greater but Less Than 5 Years**	**5 Years or Greater [2]**
Natural Gas [3] (MMBtus [4])	Forwards and Swaps	243,213,288	79,735,000	8,892,500	-
	Options	169,123,208	87,689,708	3,450,000	-
Electricity (Megawatt-hours)	Forwards and Swaps	2,537,023	2,009,505	2,008,046	1,534,695
	Congestion Revenue Rights	73,510,440	83,747,782	63,718,517	29,945,852

[1] Amounts shown reflect the total gross derivative volumes by commodity type that are expected to settle in each period.
[2] Derivatives in this category expire between 2019 and 2022.
[3] Amounts shown are for the combined positions of the electric fuels and core gas portfolios.
[4] Million British Thermal Units **.**

Presentation of Derivative Instruments in the Financial Statements

Derivatives that are subject to a master netting agreement where the right and the intent to offset assets and liabilities exists, are presented on a net basis in the Condensed Consolidated Balance Sheets. The net balances include outstanding cash collateral associated with derivative positions.

At June 30, 2014, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 61	$ (6)	$ 8	$ 63
Other noncurrent assets – other	88	(2)	-	86
Current liabilities – other	(70)	6	18	(46)
Noncurrent liabilities – other	(85)	2	-	(83)
Net commodity risk	**$ (6)**	**$ -**	**$ 26**	**$ 20**

At December 31, 2013, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	**Gross Derivative Balance**	**Netting**	**Cash Collateral**	**Total Derivative Balance**
Current assets – other	$ 42	$ (10)	$ 16	$ 48
Other noncurrent assets – other	99	(4)	-	95
Current liabilities – other	(122)	10	69	(43)
Noncurrent liabilities – other	(110)	4	2	(104)
Net commodity risk	**$ (91)**	**$ -**	**$ 87**	**$ (4)**

Gains and losses associated with price risk management activities were recorded as follows:

	Commodity Risk			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2014	2013	2014	2013
Unrealized gain (loss) - regulatory assets and liabilities [1]	$ 27	$ (23)	$ 85	$ 75
Realized loss - cost of electricity [2]	(8)	(31)	(26)	(79)
Realized loss - cost of natural gas [2]	(3)	(4)	(3)	(12)
Net commodity risk	**$ 16**	**$ (58)**	**$ 56**	**$ (16)**

[1] Unrealized gains and losses on commodity risk-related derivative instruments are recorded to regulatory liabilities or assets, respectively, 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.

The majority of the Utility's derivatives contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. At June 30, 2014, the Utility's credit rating was investment grade.

If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

The additional cash collateral that the Utility would be required to post if the credit risk-related contingency features were triggered was as follows:

	Balance at	
(in millions)	June 30, 2014	December 31, 2013
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$ (36)	$ (79)
Related derivatives in an asset position	2	4
Collateral posting in the normal course of business related to these derivatives	21	65
Net position of derivative contracts/additional collateral posting requirements [1]	**$ (13)**	**$ (10)**

[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, price risk management instruments, and other investments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

- **Level 1 –** Observable inputs that reflect quoted prices (unadjusted) for identical assets or liabilities in active markets.
- **Level 2 –** Other inputs that are directly or indirectly observable in the marketplace.
- **Level 3 –** Unobservable inputs which are supported by little or no market activities.

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

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

	Fair Value Measurements At June 30, 2014				
(in millions)	**Level 1**	**Level 2**	**Level 3**	**Netting [1]**	**Total**
Assets:					
Money market investments	$ 63	$ -	$ -	$ -	**$ 63**
Nuclear decommissioning trusts					
Money market investments	19	-	-	-	**19**
U.S. equity securities	1,128	12	-	-	**1,140**
Non-U.S. equity securities	457	2	-	-	**459**
U.S. government and agency securities	732	173	-	-	**905**
Municipal securities	-	55	-	-	**55**
Other fixed-income securities	-	172	-	-	**172**
Total nuclear decommissioning trusts [2]	**2,336**	**414**	**-**	**-**	**2,750**
Price risk management instruments (Note 7)					
Electricity	5	31	105	1	**142**
Gas	-	8	-	(1)	**7**
Total price risk management instruments	**5**	**39**	**105**	**-**	**149**
Rabbi trusts					
Fixed-income securities	-	41	-	-	**41**
Life insurance contracts	-	72	-	-	**72**
Total rabbi trusts	**-**	**113**	**-**	**-**	**113**
Long-term disability trust					
Money market investments	5	-	-	-	**5**
U.S. equity securities	-	12	-	-	**12**
Non-U.S. equity securities	-	11	-	-	**11**
Fixed-income securities	-	114	-	-	**114**
Total long-term disability trust	**5**	**137**	**-**	**-**	**142**
Other investments	71	-	-	-	**71**
Total assets	**$ 2,480**	**$ 703**	**$ 105**	**$ -**	**$ 3,288**
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$ 6	$ 29	$ 116	$ (25)	**$ 126**
Gas	-	4	-	(1)	**3**
Total liabilities	**$ 6**	**$ 33**	**$ 116**	**$ (26)**	**$ 129**

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $322 million, primarily related to deferred taxes on appreciation of investment value.

(in millions)	Fair Value Measurements At December 31, 2013 Level 1	Level 2	Level 3	Netting [1]	Total
Assets:					
Money market investments	$ 226	$ -	$ -	$ -	**$ 226**
Nuclear decommissioning trusts					
Money market investments	38	-	-	-	**38**
U.S. equity securities	1,046	11	-	-	**1,057**
Non-U.S. equity securities	457	-	-	-	**457**
U.S. government and agency securities	760	156	-	-	**916**
Municipal securities	-	25	-	-	**25**
Other fixed-income securities	-	162	-	-	**162**
Total nuclear decommissioning trusts [2]	**2,301**	**354**	**-**	**-**	**2,655**
Price risk management instruments (Note 7)					
Electricity	2	27	107	3	**139**
Gas	-	5	-	(1)	**4**
Total price risk management instruments	**2**	**32**	**107**	**2**	**143**
Rabbi trusts					
Fixed-income securities	-	39	-	-	**39**
Life insurance contracts	-	70	-	-	**70**
Total rabbi trusts	**-**	**109**	**-**	**-**	**109**
Long-term disability trust					
Money market investments	9	-	-	-	**9**
U.S. equity securities	-	14	-	-	**14**
Non-U.S. equity securities	-	12	-	-	**12**
Fixed-income securities	-	122	-	-	**122**
Total long-term disability trust	**9**	**148**	**-**	**-**	**157**
Other investments	**84**	**-**	**-**	**-**	**84**
Total assets	**$ 2,622**	**$ 643**	**$ 107**	**$ 2**	**$ 3,374**
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$ 19	$ 72	$ 137	$ (84)	**$ 144**
Gas	1	3	-	(1)	**3**
Total liabilities	**$ 20**	**$ 75**	**$ 137**	**$ (85)**	**$ 147**

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $313 million, primarily related to deferred taxes on appreciation of investment value.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. All investments, primarily consisting of equity securities, that are valued using a net asset value per share can be redeemed quarterly with notice not to exceed 90 days. Equity investments valued at net asset value per share utilize investment strategies aimed at matching the performance of indexed funds. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the six months ended June 30, 2014 and 2013.

Trust Assets

Nuclear decommissioning trust assets and other trust assets are composed primarily of equity securities, debt securities, and life insurance policies. In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks.

Equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1. Equity securities also include commingled funds that are composed of equity securities traded publicly on exchanges across multiple industry sectors in the U.S. and other regions of the world. Investments in these funds are classified as Level 2 because price quotes are readily observable and available.

Debt securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of debt securities classified as Level 2 using 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 ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

Price Risk Management Instruments

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, swaps, options, and CRRs that are traded either on an exchange or over-the-counter.

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded forwards and swaps that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded forwards and swaps or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

Long-dated power purchase agreements that are valued using significant unobservable data are classified as Level 3. These Level 3 contracts are valued using either estimated basis adjustments from liquid trading points or techniques, including extrapolation from observable prices, when a contract term extends beyond a period for which market data is available. Market and credit risk management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. CRRs are classified as Level 3 and are valued based on CRR auction prices, including historical prices. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility uses models to forecast CRR prices for those periods not covered in the auctions.

Level 3 Measurements and Sensitivity Analysis

The Utility's market and credit risk management function, which reports to the Chief Risk Officer of the Utility, is responsible for determining the fair value of the Utility's price risk management derivatives. The Utility's finance and risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 7 above.)

(in millions)	Fair Value at June 30, 2014			
Fair Value Measurement	**Assets**	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Range [1]**
Congestion revenue rights	$ 105	$ 35	Market approach	CRR auction prices	$ (17.62) - 12.04
Power purchase agreements	$ -	$ 81	Discounted cash flow	Forward prices	$ 24.77 - 59.09

[1] Represents price per megawatt-hour

(in millions)	Fair Value at December 31, 2013				
Fair Value Measurement	**Assets**	**Liabilities**	**Valuation Technique**	**Unobservable Input**	**Range [1]**
Congestion revenue rights	$ 107	$ 32	Market approach	CRR auction prices	$ (6.47) - 12.04
Power purchase agreements	$ -	$ 105	Discounted cash flow	Forward prices	$ 23.43 - 51.75

(1) Represents price per megawatt-hour

Level 3 Reconciliation

The following tables present the reconciliation for Level 3 price risk management instruments for the three and six months ended June 30, 2014 and 2013:

	Price Risk Management Instruments	
(in millions)	**2014**	**2013**
Liability balance as of April 1	$ (22)	$ (75)
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts [1]	11	(1)
Liability balance as of June 30	**$ (11)**	**$ (76)**

[1] The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

	Price Risk Management Instruments	
(in millions)	**2014**	**2013**
Liability balance as of January 1	$ (30)	$ (79)
Realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts [1]	19	3
Liability balance as of June 30	**$ (11)**	**$ (76)**

[1] The costs related to price risk management activities are recoverable through customer rates, therefore, balancing account revenue is recorded for amounts settled and purchased and there is no impact to net income. Unrealized gains and losses are deferred in regulatory liabilities and assets.

Financial Instruments

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

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at June 30, 2014 and December 31, 2013, as they are short-term in nature or have interest rates that reset daily.

- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at June 30, 2014 and December 31, 2013.

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

	At June 30, 2014		At December 31, 2013	
(in millions)	**Carrying Amount**	**Level 2 Fair Value**	**Carrying Amount**	**Level 2 Fair Value**
PG&E Corporation	$ 349	$ 354	$ 350	$ 354
Utility	12,694	14,402	12,334	13,444

Available for Sale Investments

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

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
As of June 30, 2014				
Nuclear decommissioning trusts				
Money market investments	$ 19	$ -	$ -	$ 19
Equity securities				
U.S.	266	874	-	1,140
Non-U.S.	253	207	(1)	459
Debt securities				
U.S. government and agency securities	847	60	(2)	905
Municipal securities	52	3	-	55
Other fixed-income securities	171	2	(1)	172
Total nuclear decommissioning trusts (1)	1,608	1,146	(4)	2,750
Other investments	9	62	-	71
Total	**$ 1,617**	**$ 1,208**	**$ (4)**	**$ 2,821**
As of December 31, 2013				
Nuclear decommissioning trusts				
Money market investments	$ 38	$ -	$ -	$ 38
Equity securities				
U.S.	246	811	-	1,057
Non-U.S.	215	242	-	457
Debt securities				
U.S. government and agency securities	870	51	(5)	916
Municipal securities	24	2	(1)	25
Other fixed-income securities	163	1	(2)	162
Total nuclear decommissioning trusts (1)	1,556	1,107	(8)	2,655
Other investments	13	71	-	84
Total	**$ 1,569**	**$ 1,178**	**$ (8)**	**$ 2,739**

(1) Represents amounts before deducting $322 million and $313 million at June 30, 2014 and December 31, 2013, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of debt securities by contractual maturity is as follows:

(in millions)	As of June 30, 2014
Less than 1 year	$ 16
1–5 years	502
5–10 years	248
More than 10 years	366
Total maturities of debt securities	**$ 1,132**

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2014**	**2013**	**2014**	**2013**
Proceeds from sales and maturities of nuclear decommissioning trust investments	$ 347	$ 432	$ 877	$ 795
Gross realized gains on securities held as available-for-sale	28	25	84	37
Gross realized losses on securities held as available-for-sale	(2)	(5)	(3)	(6)

NOTE 9: RESOLUTION OF REMAINING CHAPTER 11 DISPUTED CLAIMS

Various electricity suppliers filed claims in the Utility's proceeding filed under Chapter 11 of the U.S. Bankruptcy Code seeking payment for energy supplied to the Utility's customers 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 governmental entities, for overcharges incurred in the CAISO and the California Power Exchange wholesale electricity markets during this period.

While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility entered into a number of settlement agreements 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.

Any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers through resolution of the remaining disputed claims, either through settlement or through the conclusion of the various FERC and judicial proceedings, are refunded to customers through rates in future periods.

At June 30, 2014 and December 31, 2013, the remaining disputed claims liability (classified on the Condensed Consolidated Balance Sheets within accounts payable – disputed claims and customer refunds) including accrued interest (classified on the Condensed Consolidated Balance Sheets within interest payable) consisted of $766 million and $864 million, respectively.

At June 30, 2014 and December 31, 2013 the Utility held $291 million in escrow, including earned interest, for payment of the remaining net disputed claims liability. These amounts are included within restricted cash on the Condensed Consolidated Balance Sheets.

In July 2014, a settlement agreement between the Utility and an electric supplier became effective, resolving a portion of the Utility's disputed claims. The settlement will result in refunds to customers of $312 million and will be returned through rates in future periods. The Utility is uncertain when and how the remaining disputed claims will be resolved.

NOTE 10: COMMITMENTS AND CONTINGENCIES

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to natural gas matters and environmental remediation. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities.

Natural Gas Matters

Pending CPUC Investigations

As described in the 2013 Annual Report, there are three CPUC investigative enforcement proceedings pending against the Utility related to its natural gas operations and the San Bruno accident on September 9, 2010. The ALJs who are presiding over the investigations are expected to issue one or more decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when these decisions will be issued. The SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, consisting of a $300 million fine payable to the State General Fund and $1.95 billion of non-recoverable costs. Other parties, including the City of San Bruno, TURN, the CPUC's ORA, and the City and County of San Francisco, have recommended total penalties of at least $2.25 billion, including fines payable to the State General Fund of differing amounts.

Based on the CPUC's rules, after the ALJs issue their decisions, the Utility and other parties would have 30 days to file an appeal. Parties would have 15 days to respond to appeals. In addition, within 30 days after the decisions are issued, a CPUC commissioner could request that the CPUC review the decisions. If appeals are filed or a CPUC commissioner requests a review, it is uncertain when the final outcome of these investigations would be determined.

At June 30, 2014, the Condensed Consolidated Balance Sheets included an accrual of $200 million in other current liabilities for the minimum amount of fines deemed probable that the Utility will be required to pay to the State General Fund. The Utility is unable to make a better estimate due to the many variables that could affect the final outcome, including: how the total number and duration of violations will be determined; how the various penalty recommendations will be considered; how the financial and tax impact of unrecoverable costs the Utility has incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered; whether the Utility's costs to perform any required remedial actions will be considered; and how the CPUC will respond to public pressure. Future changes in these estimates or the assumptions on which they are based could have a material impact on future financial condition, results of operations, and cash flows.

The CPUC may impose fines on the Utility that are materially higher than the amount accrued and may disallow future costs, or costs that were previously authorized for recovery, including PSEP costs. Disallowed capital investments would be charged to net income in the period in which the CPUC orders such a disallowance. See "Pipeline Safety Enhancement Plan" below. Future disallowed expense and capital costs would be charged to net income in the period incurred.

Criminal Indictment

On July 30, 2014, the U.S. Attorney's Office for the Northern District of California filed a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been filed on April 1, 2014. The superseding indictment alleges 27 felony counts (increased from 12 counts alleged in the original indictment) charging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility obstructed the NTSB's investigation of the San Bruno accident in violation of a federal statute prohibiting obstruction of a federal agency's proceedings. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also alleges a maximum alternative fine under the Alternative Fines Act which states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss, unless imposition of a fine under this subsection would unduly complicate or prolong the sentencing process." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion. The Utility continues to believe that criminal charges are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their condensed consolidated financial statements as such amounts are not probable. The Utility will appear in court at a status conference that is scheduled to be held on August 18, 2014.

Other Enforcement Matters

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows also may be affected by the outcome of the following matters. They are unable to reasonably estimate the amount or range of future charges that could be incurred in connection with these matters given the wide discretion the CPUC and the SED have in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

Gas Safety Citation Program. The SED has authority to issue citations and impose fines on California gas corporations, such as the Utility, for violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. The California gas corporations are required to inform the SED of any self-identified or self-corrected violations of these regulations. The SED has discretion to impose fines or take other enforcement action to address a violation, based on the totality of the circumstances. The SED can consider various factors in determining whether to impose fines and the amount of fines, including the severity of the safety risk associated with each violation, the number and duration of the violations, whether the violation was self-reported, and whether corrective actions were taken. The SED has imposed fines ranging from $50,000 to $16.8 million in connection with several of the Utility's self-reports.

At June 30, 2014, the Utility has submitted about 65 self-reports (plus some follow-up reports) that the SED has not yet addressed. In addition, in July 2014, the Utility reported that it discovered that, contrary to its procedures, employees who perform work to fuse plastic pipes together had completed only part of their requisite re-qualification. The Utility believes that this issue does not constitute a safety concern as every plastic pipe installed in the field is tested on site and under pressure before being put into service. The Utility suspended non-emergency plastic fusion work until employees who perform this work undergo proper re-qualifications.

The Utility believes it is probable that the SED will impose fines or take other enforcement action with respect to some of the Utility's self-reports in the future. In addition, the SED has been conducting numerous compliance audits of the Utility's operating practices and has informed the Utility that the SED's audit findings include several allegations of noncompliant practices. It is reasonably possible that the SED will impose fines with respect to its audit findings. The Utility has been taking corrective actions in response to these matters.

Natural Gas Transmission Pipeline Rights-of-Way. In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey has been completed and that remediation work, including removal of the encroachments, is expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility or take other enforcement action in the future based on the Utility's failure to continuously survey its system and remove encroachments.

Other Matters. On March 3, 2014, a vacant house in Carmel, California was severely damaged due to a natural gas explosion while the Utility's employees were performing work to upgrade the main natural gas distribution pipeline in the area. There were no injuries or fatalities. A third-party engineering firm hired by the Utility determined that the root cause of the incident was "inadequate verification of system status and configuration when performing work on a live line." The Utility is implementing the recommendations made by the consultant. The CPUC, the U.S. Attorney's Office, and local Carmel officials are continuing to investigate the incident. It is reasonably possible that fines could be imposed on the Utility, or that other enforcement actions could be taken, in connection with this matter.

Pipeline Safety Enhancement Plan

On July 25, 2014, the Utility, together with the CPUC's ORA and TURN, requested that the CPUC approve a settlement agreement to resolve the Utility's PSEP Update application (submitted in October 2013). The settlement agreement proposes that the CPUC approve total PSEP-related revenue requirements (2012-2014) that reflect a $23 million reduction to expense funding, as compared to the Utility's request. For the three months ended June 30, 2014, the Utility recorded a charge against operating revenue to reflect the cumulative impact of this reduction. The settlement agreement does not propose any reductions to total PSEP capital costs of $766 million requested by the Utility in the PSEP Update application. The Utility previously has recorded cumulative charges of $549 million for PSEP-related capital costs that are expected to exceed the amount to be recovered. At June 30, 2014, approximately $400 million of PSEP-related capital costs is recorded in property, plant, and equipment on the Condensed Consolidated Balance Sheets. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected and to the extent the CPUC authorizes total capital costs that are lower than $766 million. The parties have requested the CPUC's approval of the settlement agreement by December 1, 2014. The Utility's ability to recover PSEP-related costs also could be affected by the final decisions to be issued in the CPUC's pending investigations discussed above.

Class Action Complaint

In August 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. The plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs seek restitution and disgorgement, as well as compensatory and punitive damages. PG&E Corporation and the Utility contest the plaintiffs' allegations. In May 2013, the court granted PG&E Corporation's and the Utility's request to dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. The plaintiffs have appealed the court's ruling to the California Court of Appeal. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses, if any, that may be incurred in connection with this matter if the lower court's ruling is reversed.

Legal and Regulatory Contingencies

Accruals for other legal and regulatory contingencies (excluding amounts related to natural gas matters above) totaled $35 million at June 30, 2014 and $43 million at December 31, 2013. These amounts are included in other current liabilities in the Condensed Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

Environmental Remediation Contingencies

The Utility's environmental remediation liability is primarily included in non-current liabilities on the Condensed Consolidated Balance Sheets and is composed of the following:

	Balance at	
(in millions)	**June 30, 2014**	**December 31, 2013**
Topock natural gas compressor station [1]	$ 269	$ 264
Hinkley natural gas compressor station [1]	170	190
Former manufactured gas plant sites owned by the Utility or third parties	183	184
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites	157	160
Fossil fuel-fired generation facilities and sites	99	102
Total environmental remediation liability	**$ 878**	**$ 900**

(1) See "Natural Gas Compressor Station Sites" below.

At June 30, 2014 the Utility expected to recover $582 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites (including the Topock site) without a reasonableness review. The Utility may incur environmental remediation costs that it does not seek to recover in rates, such as the costs associated with the Hinkley site.

Natural Gas Compressor Station Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. One of these stations is located near Hinkley, California and is referred to below as the "Hinkley site." Another station is located near Needles, California and is referred to below as the "Topock site." The Utility is also required to take measures to abate the effects of the contamination on the environment.

Hinkley Site

The Utility's remediation and abatement efforts at the Hinkley site are subject to the regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In 2013, the Regional Board certified a final environmental report evaluating the Utility's proposed remedial methods to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The Regional Board is expected to issue final project permits for in-situ remediation in late 2014 and the final cleanup and abatement order in late 2014 or early 2015. As final permits and orders are issued, the Utility expects to obtain additional clarity on the total costs associated with the final remedy and related activities. The Utility has implemented interim remediation measures to reduce the mass of the chromium plume, monitor and control movement of the plume, and provide replacement water to affected residents under its whole house water replacement program (as described in the 2013 Annual Report). The State of California has established a final drinking water standard for hexavalent chromium that became effective on July 1, 2014. The Utility is evaluating the new standard but does not believe any related changes to its interim measures will have a material impact on its environmental remediation liability.

The Utility's environmental remediation liability at June 30, 2014 reflects the Utility's best estimate of probable future costs associated with its final remediation plan and interim remediation measures. Future costs will depend on many factors, including the levels of hexavalent chromium the Utility is required to use as the standard for remediation, the required time period by which those standards must be met, and the nature and extent of the chromium contamination. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition, results of operations, and cash flows.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California Department of Toxic Substances Control and the U.S. Department of the Interior. The Utility expects to submit its 90% remedial design plan in late 2014 and its final remedial design plan in early 2015, which would seek approval to begin construction of an in-situ groundwater treatment system that will convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The Utility has implemented interim remediation measures, including a system of extraction wells and a treatment plant designed to prevent movement of the chromium plume toward the Colorado River. The Utility's environmental remediation liability at June 30, 2014 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

Reasonably Possible Environmental Contingencies

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.7 billion (including amounts related to the Hinkley and Topock sites described above) 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. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations during the period in which they are recorded.

Tax Matters

In June 2014, the Joint Committee on Taxation of the U.S. Congress approved the IRS closing agreement for the 2008 and 2010 audit years. The IRS is currently reviewing several matters pertaining to the 2011 and 2012 tax returns. The most significant of these matters relates to the repairs accounting method changes.

The IRS has been working with the utility industry to provide guidance concerning the deductibility of repairs. PG&E Corporation and the Utility expect the IRS to issue guidance with respect to repairs made in the natural gas transmission and distribution businesses during 2014. PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months depending on the guidance to be issued by the IRS and the resolution of the IRS audits related to the 2011 and 2012 tax returns. As of June 30, 2014, it is reasonably possible that unrecognized tax benefits will decrease by approximately $370 million within the next 12 months, and most of this decrease would not impact net income.

There were no other significant developments to tax matters during the six months ended June 30, 2014 . (Refer to Note 8 of the Notes to the Consolidated Financial Statements in the 2013 Annual Report.)

Nuclear Insurance

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $3.2 billion per nuclear incident and $2.6 billion per non-nuclear incident for Diablo Canyon. Humboldt Bay Unit 3 has up to $131 million of coverage for nuclear and non-nuclear property damages. NEIL also provides coverage for damages caused by acts of terrorism at nuclear power plants.

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 $13.6 billion. The Utility purchased the maximum available public liability insurance of $375 million for Diablo Canyon. The balance of the $13.6 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. In addition, Congress could impose additional revenue-raising measures to pay claims. The Price-Anderson Act does not apply to 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. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of $375 million per incident. 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 liability insurance. (See Note 14 of the Notes to the Consolidated Financial Statements of the 2013 Annual Report for additional information.)

Commitments

In the ordinary course of business, the Utility enters into various agreements to purchase power and electric capacity; natural gas supply, transportation, and storage; nuclear fuel supply and services; and various other commitments. The Utility disclosed its commitments at December 31, 2013 in Note 14 of the Notes to the Consolidated Financial Statements in the 2013 Annual Report. During the six months ended June 30, 2014, several purchase power agreements the Utility entered into with renewable energy facilities were approved by the CPUC and completed major milestones with respect to construction, resulting in a total commitment amount of $1.7 billion over the next 25 years.

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

OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, 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 primarily by the CPUC and the FERC. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity 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 interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility also is subject to the jurisdiction of other federal, state, and local governmental agencies.

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. It should also be read in conjunction with the 2013 Annual Report.

Summary of Changes in Net Income and Earnings per Share

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS compared to the prior year (see "Results of Operations" below for additional information):

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	**Earnings**	**EPS (Diluted)**	**Earnings**	**EPS (Diluted)**
Income Available for Common Shareholders - 2013	$ 328	$ 0.74	$ 567	$ 1.29
Natural gas matters [1]	(40)	(0.08)	(27)	(0.06)
Growth in rate base earnings [2]	6	0.01	11	0.02
Timing of 2014 GRC expense recovery [3]	(21)	(0.04)	(41)	(0.08)
Increase in shares outstanding [4]	-	(0.04)	-	(0.07)
Other	(6)	(0.02)	(16)	(0.04)
Income Available for Common Shareholders - 2014	**$ 267**	**$ 0.57**	**$ 494**	**$ 1.06**

[1] Represents the increase in net costs related to natural gas matters during t he three and six months ended June 30, 2014 as compared to the same periods in 2013. These amounts are not recoverable through rates. See "Operating and Maintenance" below.

[2] Represents the impact of the increase in rate base as authorized in various rate cases during the three and six months ended June 30, 2014 as compared to the same periods in 2013 .

[3] Represents additional capital-related expenses during the three and six months ended June 30, 2014 as compared to the same periods in 2013, with no corresponding increase in revenue. The CPUC has not yet issued a final decision on the Utility's 2014 GRC request to increase revenues beginning on January 1, 2014. Upon receipt of a final decision, the Utility has been authorized to collect any final adopted increase in revenue requirements from January 1, 2014.

[4] Represents the impact of a higher number of weighted average shares of common stock outstanding during t he three and six months ended June 30, 2014 as compared to the same periods in 2013. PG&E Corporation issues shares to fund its equity contributions to the Utility to maintain the Utility's capital structure and fund operations, including unrecovered expenses related to natural gas matters.

Key Factors Affecting Financial Results

PG&E Corporation and the Utility believe that their future results of operations, financial condition, and cash flows will be materially affected by the following factors :

- *The Timing and Outcome of Ratemaking Proceedings* . The majority of the Utility's revenue requirements for the next several years will be determined by the outcomes of the 2014 GRC and the 2015 GT&S rate case. A proposed decision was recently issued in the Utility's GRC that recommended an increase in 2014 revenue requirements of $453 million, or 6.8% over currently authorized amounts, compared to the Utility's requested increase of $1,160 million. The proposed decision also recommended attrition increases of $322 million for 2015 and $371 million for 2016. Upon receipt of a final decision, the Utility has been authorized to collect any final adopted increase in revenue requirements from January 1, 2014. (See "2014 General Rate Case" below.) In the GT&S rate case, the Utility is seeking an increase in its 2015 revenue requirements of $555 million over the comparable authorized revenues for 2014, as well as attrition increases for 2016 and 2017. After the CPUC issues a final decision, the Utility's authorized revenue requirements will be adjusted as of January 1, 2015. (See "2015 Gas Transmission and Storage Rate Case" below.) In addition, the Utility has two transmission owner rate cases pending at the FERC. (See "FERC Transmission Owner Rate Cases" below.) The positions taken by the intervening parties in these proceedings are often contentious and the outcome can be affected by many factors, including general economic conditions, the level of customer rates, regulatory policies, and political considerations.

- *The Ability of the Utility to Control Operating Costs and Capital Expenditures.* Net income is negatively affected when the authorized revenues are not sufficient for the Utility to recover the costs it actually incurs to provide utility services. (See "Results of Operations – Utility Revenues and Costs That Impact Earnings" below.) During the last GRC and GT&S rate case periods, the Utility incurred costs to improve the safety and reliability of its electric and natural gas operations that materially exceeded annual authorized revenues. PG&E Corporation's and the Utility's future results of operations, financial condition, and cash flows could be materially affected if the Utility's actual costs differ from the amounts assumed or authorized in the final 2014 GRC and 2015 GT&S rate case decisions. (See "Regulatory Matters" below.) The Utility also forecasts that in 2014 it will incur unrecovered pipeline-related expenses ranging from $350 million to $450 million, including costs to perform continuing work under the Utility's PSEP and other gas transmission safety work, as well as legal and other expenses. The Utility also could record charges in 2014 for PSEP capital if the Utility's cost forecasts increase. (See "Pipeline Safety Enhancement Plan" below.) Differences between the amount or timing of the Utility's actual costs and forecasted or authorized amounts may affect the Utility's ability to earn its authorized ROE.

- *The Outcome of Pending Investigations and Enforcement Matters.* Three CPUC investigations are still pending against the Utility related to its natural gas operations and the San Bruno accident. It is uncertain when the outcome of these investigations will be determined. Under the SED's penalty recommendation, the Utility estimates that its total unrecovered costs and fines related to natural gas transmission operations would be about $4.5 billion. (See "Pending CPUC Investigations" below.) The U.S. Attorney's Office has filed a superseding criminal indictment against the Utility alleging that it violated the Pipeline Safety Act and illegally obstructed the NTSB's investigation of the San Bruno accident that occurred on September 9, 2010. Based on the superseding indictment's allegation that the Utility derived gross gains of approximately $281 million, and that victims suffered losses of approximately $565 million, the maximum alternative fine would be approximately $1.13 billion. (See "Criminal Indictment" and "Item 1.A. Risk Factors" below.) In addition, fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the natural gas matters described under "Other Enforcement Matters" below.

- *The Amount and Timing of the Utility's Financing Needs* . PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. For the six months ended June 30, 2014, PG&E Corporation issued common stock of $589 million and made equity contributions to the Utility of $580 million. PG&E Corporation forecasts that it will continue issuing a material amount of equity in 2014, primarily to support the Utility's capital expenditures and to fund unrecovered costs. Depending on the outcome of the pending investigations and other enforcement matters described above, PG&E Corporation may be required to issue additional common stock to fund its equity contributions as the Utility pays fines and incurs additional unrecovered pipeline-related costs. These additional issuances could have a material dilutive effect on PG&E Corporation's EPS. PG&E Corporation's and the Utility's ability to access the capital markets and the terms and rates of future financings could be affected by changes in their respective credit ratings, the outcome of the matters discussed under "Natural Gas Matters" below, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see the section entitled "Risk Factors" in the 2013 Annual Report and "Item 1A. Risk Factors" below. In addition, this quarterly report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which 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. See the section entitled "Cautionary Language Regarding Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

RESULTS OF OPERATIONS

PG&E Corporation

The consolidated results of operations consist primarily of balances related to the Utility, which are discussed below. The following table provides a summary of net income for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	**2014**	**2013**	**2014**	**2013**
Consolidated Total	$ 267	$ 328	$ 494	$ 567
PG&E Corporation	21	3	23	8
Utility	$ 246	$ 325	$ 471	$ 559

PG&E Corporation's net income consists primarily of interest expense on long-term debt, other income from investments, and income taxes. Results for 2014 include a gain on investments of approximately $20 million, with no similar activity in 2013.

Utility

The table below shows certain items from the Utility's Condensed Consolidated Statements of Income for the three and six months ended June 30, 2014 and 2013. The tables separately identify the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized, such as the payment of pension costs, and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

Revenues that impact earnings are primarily those that have been authorized by the CPUC and the FERC to recover the Utility's costs to own and operate its assets and to provide the Utility an opportunity to earn its authorized rate of return on rate base. Expenses that impact earnings are primarily those that the Utility incurs to own and operate its assets.

	Three Months Ended June 30, 2014			Three Months Ended June 30, 2013		
	Revenues/Costs:			Revenues/Costs:		
(in millions)	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$ 1,632	$ 1,600	$ 3,232	$ 1,611	$ 1,446	$ 3,057
Natural gas operating revenues	454	265	719	431	287	718
Total operating revenues	**2,086**	**1,865**	**3,951**	**2,042**	**1,733**	**3,775**
Cost of electricity	-	1,349	1,349	-	1,189	1,189
Cost of natural gas	-	200	200	-	179	179
Operating and maintenance	1,005	316	1,321	891	365	1,256
Depreciation, amortization, and decommissioning	556	-	556	516	-	516
Total operating expenses	**1,561**	**1,865**	**3,426**	**1,407**	**1,733**	**3,140**
Operating income	**525**	**-**	**525**	**635**	**-**	**635**
Interest income [(1)]			3			3
Interest expense [(1)]			(185)			(171)
Other income, net [(1)]			17			22
Income before income taxes			360			489
Income tax provision [(1)]			110			160
Net income			250			329
Preferred stock dividend requirement [(1)]			4			4
Income Available for Common Stock			**$ 246**			**$ 325**

[(1)] These items impacted earnings for the three months ended June 30, 2014 and 2013.

	Six Months Ended June 30, 2014			Six Months Ended June 30, 2013		
	Revenues/Costs:			Revenues/Costs:		
(in millions)	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$ 3,217	$ 3,015	$ 6,232	$ 3,198	$ 2,657	$ 5,855
Natural gas operating revenues	925	684	1,609	870	721	1,591
Total operating revenues	**4,142**	**3,699**	**7,841**	**4,068**	**3,378**	**7,446**
Cost of electricity	-	2,559	2,559	-	2,172	2,172
Cost of natural gas	-	560	560	-	525	525
Operating and maintenance	2,038	580	2,618	1,911	681	2,592
Depreciation, amortization, and decommissioning	1,094	-	1,094	1,019	-	1,019
Total operating expenses	**3,132**	**3,699**	**6,831**	**2,930**	**3,378**	**6,308**
Operating income	**1,010**	**-**	**1,010**	**1,138**	**-**	**1,138**
Interest income (1)			5			4
Interest expense (1)			(364)			(341)
Other income, net (1)			37			46
Income before income taxes			688			847
Income tax provision (1)			210			281
Net income			478			566
Preferred stock dividend requirement (1)			7			7
Income Available for Common Stock			**$ 471**			**$ 559**

(1) These items impacted earnings for the six months ended June 30, 2014 and 2013.

Utility Revenues and Costs that Impact Earnings

The following discussion presents the Utility's operating results for the three and six months ended June 30, 2014 and 2013, focusing on revenues and expenses that had an impact on earnings for these periods.

Operating Revenues

The Utility's electric and natural gas operating revenues that impacted earnings increased by $44 million, or 2%, and by $74 million, or 2%, in the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013, primarily due to increases in revenues authorized by the FERC in the electric transmission rate case and revenues the CPUC authorized the Utility to collect for recovery of certain PSEP-related costs, as well as other higher gas transmission revenues resulting from additional demand for gas-fired generation (see "Cost of Electricity" below). The increase for both periods was partially offset by $25 million of revenue authorized by the CPUC in 2013 for recovery of the Utility's incremental costs of responding to storms and wildfires from 2009 to 2011, with no similar activity in 2014.

In June 2014, a proposed decision was issued in the Utility's 2014 GRC that recommends an increase in revenue requirements of $453 million, or 6.8%, over currently authorized amounts. Upon receipt of a final decision, the Utility has been authorized to collect any final adopted increase in revenue requirements from January 1, 2014. The Utility has not recorded any revenues associated with the GRC proposed decision in the three and six months ended June 30, 2014. See "Regulatory Matters" below.

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased by $114 million, or 13%, and by $127 million, or 7%, in the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013. The increases are primarily due to higher unrecovered costs of $68 million and $46 million, respectively, incurred in connection with natural gas matters (see table below). The remaining increases consisted of benefit-related expenses and other expenses.

The following table provides a summary of the Utility's costs associated with natural gas matters that are not recoverable through rates:

(in millions)	**Three Months Ended June 30, 2014**	**Three Months Ended June 30, 2013**	**Six Months Ended June 30, 2014**	**Six Months Ended June 30, 2013**
Pipeline-related expenses [1]	$ 97	$ 74	$ 137	$ 136
Insurance recoveries	-	(45)	-	(45)
Total natural gas matters	**$ 97**	**$ 29**	**$ 137**	**$ 91**

[1] Includes $58 million for work performed under the PSEP and $64 million for other gas safety-related work for the six months ended June 30, 2014. See "Natural Gas Matters" below.

There were no additional charges recorded in the three and six months ended June 30, 2014 and 2013, respectively, related to natural gas matters for disallowed capital, fines, or third-party claims. As described in "Key Factors Affecting Financial Results" above, the Utility forecasts that its total unrecoverable pipeline-related expenses in 2014 will range from $350 million to $450 million. See "Natural Gas Matters" below.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by $40 million, or 8%, and by $75 million, or 7%, in the three and six months ended June 30, 2014, respectively, compared to the same periods in 2013, primarily due to the impact of capital additions.

Interest Income, Interest Expense, and Other Income, Net

There were no material changes to interest income, interest expense, and other income, net for the periods presented.

Income Tax Provision

The Utility's income tax provision decreased by $50 million, or 31%, and by $71 million, or 25%, in the three and six months ended June 30, 2014 compared to the same periods in 2013. The effective tax rates were 31% and 33% in the three and six months ended June 30, 2014 and 2013, respectively. The decrease in effective tax rates for both periods was primarily due to higher deductible software development costs in 2014.

Utility Revenues and Costs that do not Impact Earnings

Cost of Electricity

The Utility's cost of electricity includes the costs of power purchased from third parties, transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.) The volume of power purchased by the Utility is driven by customer demand, the availability of the Utility's own generation facilities, and the cost effectiveness of each source of electricity. Additionally, the cost of electricity is impacted by the higher cost of procuring renewable energy as the Utility increases the amount of its renewable energy deliveries to comply with California legislative and regulatory requirements, and by costs associated with complying with California's GHG laws.

(in millions)	**Three Months Ended June 30, 2014**	**Three Months Ended June 30, 2013**	**Six Months Ended June 30, 2014**	**Six Months Ended June 30, 2013**
Cost of purchased power	$ 1,287	$ 1,120	$ 2,399	$ 2,030
Fuel used in own generation facilities	62	69	160	142
Total cost of electricity	**$ 1,349**	**$ 1,189**	**$ 2,559**	**$ 2,172**
Average cost of purchased power per kWh [1]	$ 0.097	$ 0.088	$ 0.093	$ 0.086
Total purchased power (in millions of kWh)	**13,320**	**12,788**	**25,788**	**23,674**

[1] Kilowatt-hour

The Utility's cost of electricity for 2014 is expected to continue to be higher due to the low levels of hydroelectric generation caused by the drought in California and higher market prices for natural gas used to fuel conventional generation resources. The Utility expects that it will be able to continue to recover the increasing cost of electricity through rates. If the Utility's forecasted aggregate over-collections or under-collections of its electricity procurement costs exceed five percent of its prior year electricity procurement revenues, the CPUC may authorize an adjustment to retail electricity generation rates before the next annual update, which is January 1, 2015.

Cost of Gas

The Utility's cost of natural gas includes the costs of procurement, storage, transportation of natural gas and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, changes in customer demand, and by costs associated with complying with California's GHG laws.

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(in millions)	**2014**	**2013**	**2014**	**2013**
Cost of natural gas sold	$ 165	$ 137	$ 489	$ 437
Transportation cost of natural gas sold	35	42	71	88
Total cost of natural gas	**$ 200**	**$ 179**	**$ 560**	**$ 525**
Average cost per Mcf [1] of natural gas sold	$ 4.34	$ 3.43	$ 4.22	$ 3.08
Total natural gas sold (in millions of Mcf)	**38**	**40**	**116**	**142**

[1] One thousand cubic feet

Operating and Maintenance Expenses

The Utility's operating expenses also include certain recoverable costs that the Utility incurs as part of its operations such as public purpose programs, pension, and other recurring expenses. If the Utility were to spend over authorized amounts, these expenses could have an impact to earnings.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

The Utility's ability to fund operations and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure consisting of 52% equity and 48% debt and preferred stock. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs. The CPUC authorizes the aggregate amount of long-term debt and short-term debt that the Utility may issue and authorizes the Utility to recover its related debt financing costs.

The Utility's future equity needs will continue to be affected by costs that are not recoverable through rates, including costs related to natural gas matters, and will also be affected by various other factors described in "Operating Activities" below. The Utility's equity needs would also increase to the extent it is required to pay fines or penalties in connection with the CPUC's pending investigations and other enforcement matters related to its natural gas operations. (See "Natural Gas Matters" below.) Further, given the Utility's significant ongoing capital expenditures, the Utility will continue to need equity contributions from PG&E Corporation to maintain its authorized capital structure.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and pay dividends, primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets. PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. These contributions have been dilutive to PG&E Corporation's EPS to the extent that the equity contributions are used by the Utility to restore equity that has been depleted by unrecoverable costs and charges. Future issuances of common stock by PG&E Corporation to fund equity contributions could have a material dilutive effect on EPS depending upon the ultimate outcomes of the CPUC's pending investigations, the criminal proceeding and other enforcement matters, as well as the extent to which the Utility incurs costs that are not recoverable through rates.

2014 Financings

PG&E Corporation

In February 2014, PG&E Corporation issued $350 million principal amount of 2.40% Senior Notes due March 1, 2019. The proceeds were used to repay the 5.75% Senior Notes, in the principal outstanding amount of $350 million. PG&E Corporation also entered into a new equity distribution agreement in February 2014 providing for the sale of its common stock having an aggregate gross sales price of up to $500 million.

PG&E Corporation issued common stock in the following transactions:

- During the six months ended June 30, 2014, 4 million shares were issued for cash proceeds of $160 million under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans; and

- During the three and six months ended June 30, 2014, PG&E Corporation sold 5 and 10 million shares under the February 2014 equity distribution agreement for cash proceeds of $206 and $429 million, net of commissions paid of $2 and $4 million, respectively.

The proceeds from these sales were used for general corporate purposes, including the infusion of equity into the Utility. For the six months ended June 30, 2014, PG&E Corporation made equity contributions to the Utility of $580 million. On July 30, 2014, PG&E Corporation made an equity contribution to the Utility of $125 million. PG&E Corporation forecasts that it will need to continue to issue additional common stock to fund the Utility's equity needs.

Utility

In February 2014, the Utility issued $450 million principal amount of 3.75% Senior Notes due February 15, 2024 and $450 million principal amount of 4.75% Senior Notes due February 15, 2044. The proceeds were used to repay the 4.80% Senior Notes, in the principal outstanding amount of $539 million, to fund capital expenditures, and for general corporate purposes. In addition, in May 2014, the Utility issued $300 million principal amount of Floating Rate Senior Notes due May 11, 2015. The proceeds were used for general corporate purposes, including the repayment of a portion of outstanding commercial paper.

Revolving Credit Facilities and Commercial Paper Program

In April 2014, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 1, 2018 to April 1, 2019. PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $1.75 billion, respectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities.

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings at June 30, 2014:

(in millions)	Termination Date	Facility Limit	Letters of Credit Outstanding	Borrowings	Commercial Paper	Facility Availability
PG&E Corporation	April 2019	$ 300 (1)	$ -	$ -	$ 112	$ 188
Utility	April 2019	3,000 (2)	86	-	1,041	1,873
Total revolving credit facilities		**$ 3,300**	**$ 86**	**$ -**	**$ 1,153**	**$ 2,061**

(1) Includes a $100 million sublimit for letters of credit and a $100 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.
(2) Includes a $1.0 billion sublimit for letters of credit and a $300 million commitment for loans that are made available on a same-day basis and are repayable in full within 7 days.

For the six months ended June 30, 2014, the average outstanding borrowings under PG&E Corporation's revolving credit facility were $54 million and the maximum outstanding balance was $260 million. In February 2014, PG&E Corporation repaid the full outstanding borrowings of $260 million and initiated borrowing under its commercial paper program established in January 2014. For the six months ended June 30, 2014, PG&E Corporation's average outstanding commercial paper balance was $138 million and the maximum outstanding balance during the period was $260 million.

For the six months ended June 30, 2014, the Utility's average outstanding commercial paper balance was $957 million and the maximum outstanding balance during the period was $1.4 billion. The Utility has not borrowed under its credit facility during 2014.

At June 30, 2014, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

In June 2014, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $215 million, of which approximately $210 million was paid on July 15, 2014 to shareholders of record on June 30, 2014.

In June 2014, the Board of Directors of the Utility declared a common stock dividend of $179 million that was paid to PG&E Corporation on June 19, 2014.

In June 2014, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on August 15, 2014, to shareholders of record on July 31, 2014.

Utility

Operating Activities

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

The Utility's cash flows from operating activities for the six months ended June 30, 2014 and 2013 were as follows:

	Six Months Ended June 30,	
(in millions)	**2014**	**2013**
Net income	$ 478	$ 566
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,094	1,019
Allowance for equity funds used during construction	(46)	(52)
Deferred income taxes and tax credits, net	18	337
Other	108	126
Net effect of changes in operating assets and liabilities	(391)	(532)
Net cash provided by operating activities	**$ 1,261**	**$ 1,464**

During the six months ended June 30, 2014, net cash provided by operating activities decreased by $203 million compared to the same period in 2013. This decrease consisted of various fluctuations in cash flows including higher purchased power costs and natural gas costs during 2014 as compared to 2013.

Future cash flow from operating activities will be affected by various factors, including:

- the timing and outcome of ratemaking proceedings, including the 2014 GRC and 2015 GT&S rate cases;
- the timing and amount of tax payments, tax refunds, net collateral payments, and interest payments;
- the timing and amount of insurance recoveries related to third-party claims (see "Natural Gas Matters" below);
- the timing and amount of fines or penalties that may be imposed, as well as any costs associated with remedial actions the Utility may be required to implement (see "Natural Gas Matters" below);
- the timing and amount of costs the Utility incurs, but does not recover, to improve the safety and reliability of its natural gas system (see "Operating and Maintenance" above and "Natural Gas Matters" below); and
- 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 (see Note 9 of the Notes to the Condensed Consolidated Financial Statements).

Investing Activities

The Utility's investing activities primarily consist of construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility's nuclear generation facilities.

The Utility's cash flows from investing activities for the six months ended June 30, 2014 and 2013 were as follows:

	Six Months Ended June 30,	
(in millions)	**2014**	**2013**
Capital expenditures	$ (2,320)	$ (2,521)
Decrease in restricted cash	2	25
Proceeds from sales and maturities of nuclear decommissioning trust investments	877	795
Purchases of nuclear decommissioning trust investments	(873)	(786)
Other	17	8
Net cash used in investing activities	**$ (2,297)**	**$ (2,479)**

Net cash used in investing activities decreased by $182 million during the six months ended June 30, 2014 compared to the same period in 2013 primarily due to lower capital expenditures.

Future cash flows used in investing activities are largely dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur between $5 billion and $6 billion in capital expenditures for 2014, including PSEP-related expenditures.

Financing Activities

The Utility's cash flows from financing activities for the six months ended June 30, 2014 and 2013 were as follows:

	Six Months Ended June 30,	
(in millions)	**2014**	**2013**
Net issuances of commercial paper, net of discount of $1 at respective dates	$ 125	$ 321
Proceeds from issuance of short-term debt, net of issuance costs	300	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $11 and $8 at respective dates	889	742
Repayments of long-term debt	(539)	(461)
Preferred stock dividends paid	(7)	(7)
Common stock dividends paid	(358)	(358)
Equity contribution	580	665
Other	51	(20)
Net cash provided by financing activities	**$ 1,041**	**$ 882**

During the six months ended June 30, 2014, net cash provided by financing activities increased by $159 million compared to the same period in 2013. 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, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on commercial paper and other short-term debt to fund temporary financing needs.

NATURAL GAS MATTERS

Since the San Bruno accident occurred on September 9, 2010, PG&E Corporation and the Utility have incurred total cumulative charges of approximately $2.6 billion related to natural gas matters that are not recoverable through rates, as shown in the following table:

(in millions)	Cumulative December 31, 2013	Six Months Ended June 30, 2014	Cumulative June 30, 2014
Pipeline-related expenses [1]	$ 1,410	$ 137	$ 1,547
Disallowed capital [2]	549	-	549
Accrued fines [3]	239	-	239
Third-party liability claims [4]	565	-	565
Insurance recoveries [4]	(354)	-	(354)
Contribution to City of San Bruno	70	-	70
Total natural gas matters	**$ 2,479**	**$ 137**	**$ 2,616**

(1) Cumulative costs through June 30, 2014 included PSEP expenses of approximately $794 million and other gas safety-related work of $411 million. The Utility forecasts that it will incur total unrecovered pipeline-related expenses ranging from $350 million to $450 million in 2014.
(2) See "Pipeline Safety Enhancement Plan" below.
(3) See "Pending CPUC Investigations" below.
(4) See "Third-Party Liability Claims" below.

Pending CPUC Investigations

As described in the 2013 Annual Report, there are three CPUC investigative enforcement proceedings pending against the Utility related to its natural gas operations and the San Bruno accident. The ALJs who are presiding over the investigations are expected to issue one or more decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when these decisions will be issued. In July 2013, the SED recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, allocated as follows: (1) $300 million as a fine payable to the State General Fund, (2) $435 million for a portion of costs related to the Utility's PSEP that were previously disallowed by the CPUC and funded by shareholders, and (3) $1.5 billion to perform PSEP work that was previously approved by the CPUC, implement operational remedies, and for future costs. Other parties, including the City of San Bruno, TURN, the CPUC's ORA, and the City and County of San Francisco, have recommended total penalties of at least $2.25 billion, including fines payable to the State General Fund of differing amounts.

Aside from any penalty resulting from the CPUC's investigations, the Utility estimates that its total unrecovered costs for gas pipeline safety-related work incurred or committed over the next several years will be approximately $2.7 billion, including cumulative charges reflected in the table above for unrecovered PSEP expenses and capital costs and other gas safety-related work (see "pipeline-related expenses" and "disallowed capital"). If the SED's penalty recommendation is adopted by the CPUC, the Utility estimates that its total unrecovered costs related to natural gas transmission operations would be about $4.5 billion, including: (1) the approximately $2.7 billion discussed in the preceding sentence; (2) a fine of $300 million; and (3) $1.5 billion to perform incremental shareholder-funded gas safety work.

Based on the CPUC's rules, after the ALJs issue their decisions, the Utility and other parties would have 30 days to file an appeal. Parties would have 15 days to respond to appeals. In addition, within 30 days after the decisions are issued, a CPUC commissioner could request that the CPUC review the decisions. If appeals are filed or a CPUC commissioner requests a review, it is uncertain when the final outcome of these investigations would be determined.

At June 30, 2014, the Condensed Consolidated Balance Sheets included an accrual of $200 million in other current liabilities for the minimum amount of fines deemed probable that the Utility will be required to pay to the State General Fund. The Utility is unable to make a better estimate due to the many variables that could affect the final outcome, including: how the total number and duration of violations will be determined; how the various penalty recommendations will be considered; how the financial and tax impact of unrecoverable costs the Utility has incurred, and will continue to incur, to improve the safety and reliability of its pipeline system, will be considered; whether the Utility's costs to perform any required remedial actions will be considered ; and how the CPUC will respond to public pressure. Future changes in these estimates or the assumptions on which they are based could have a material impact on future financial condition, results of operations, and cash flows.

The CPUC may impose fines on the Utility that are materially higher than the amount accrued and may disallow future costs, or costs that were previously authorized for recovery, including PSEP costs. Disallowed capital investments would be charged to net income in the period in which the CPUC orders such a disallowance. See "Pipeline Safety Enhancement Plan" below. Future disallowed expense and capital costs would be charged to net income in the period incurred.

On July 28, 2014, the City of San Bruno filed a motion alleging that the Utility violated CPUC rules that prohibit certain communications between "an interested person," such as the Utility, and a "decision maker," such as a Commissioner, regarding adjudicatory proceedings, such as the pending investigations. The City of San Bruno requested that the CPUC issue an "order to show cause" why the Utility should not be penalized for the alleged violations. The City of San Bruno also filed a motion seeking the recusal of the President of the CPUC from serving as an assigned Commissioner in the investigatory proceedings and from voting on the final decisions. Responses to the motions are due on August 12, 2014.

Criminal Indictment

On July 30, 2014, the U.S. Attorney's Office for the Northern District of California filed a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been filed on April 1, 2014. The superseding indictment alleges 27 felony counts (increased from 12 counts alleged in the original indictment) charging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility obstructed the NTSB's investigation of the San Bruno accident in violation of a federal statute prohibiting obstruction of a federal agency's proceedings. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also alleges a maximum alternative fine under the Alternative Fines Act which states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss, unless imposition of a fine under this subsection would unduly complicate or prolong the sentencing process." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion. The Utility continues to believe that criminal charges are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their condensed consolidated financial statements as such amounts are not probable. The Utility will appear in court at a status conference that is scheduled to be held on August 18, 2014. See the discussion in "Item 1A. Risk Factors" below.

Other Enforcement Matters

PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows also may be affected by the outcome of the following matters. They are unable to reasonably estimate the amount or range of future charges that could be incurred in connection with these matters given the wide discretion the CPUC and the SED have in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

Gas Safety Citation Program. The SED has authority to issue citations and impose fines on California gas corporations, such as the Utility, for violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. The California gas corporations are required to inform the SED of any self-identified or self-corrected violations of these regulations. (California law also requires the CPUC to adopt a safety enforcement program for California electric corporations. See "Regulatory Matters" below.) The SED has discretion to impose fines or take other enforcement action to address a violation, based on the totality of the circumstances. The SED can consider various factors in determining whether to impose fines and the amount of fines, including the severity of the safety risk associated with each violation, the number and duration of the violations, whether the violation was self-reported, and whether corrective actions were taken. The SED has imposed fines ranging from $50,000 to $16.8 million in connection with several of the Utility's self-reports.

At June 30, 2014, the Utility has submitted about 65 self-reports (plus some follow-up reports) that the SED has not yet addressed. In addition, in July 2014, the Utility reported that it discovered that, contrary to its procedures, employees who perform work to fuse plastic pipes together had completed only part of their requisite re-qualification. The Utility believes that this issue does not constitute a safety concern as every plastic pipe installed in the field is tested on site and under pressure before being put into service. The Utility suspended non-emergency plastic fusion work until employees who perform this work undergo proper re-qualifications.

The Utility believes it is probable that the SED will impose fines or take other enforcement action with respect to some of the Utility's self-reports in the future. In addition, the SED has been conducting numerous compliance audits of the Utility's operating practices and has informed the Utility that the SED's audit findings include several allegations of noncompliant practices. It is reasonably possible that the SED will impose fines with respect to its audit findings. The Utility has been taking corrective actions in response to these matters.

Natural Gas Transmission Pipeline Rights-of-Way. In 2012, the Utility notified the CPUC and the SED that the Utility planned to complete a system-wide survey of its transmission pipelines in an effort to identify encroachments (such as building structures and vegetation overgrowth) on the Utility's pipeline rights-of-way. The Utility also submitted a proposed compliance plan that set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey has been completed and that remediation work, including removal of the encroachments, is expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility or take other enforcement action in the future based on the Utility's failure to continuously survey its system and remove encroachments.

Other Matters. On March 3, 2014, a vacant house in Carmel, California was severely damaged due to a natural gas explosion while the Utility's employees were performing work to upgrade the main natural gas distribution pipeline in the area. There were no injuries or fatalities. A third-party engineering firm hired by the Utility determined that the root cause of the incident was "inadequate verification of system status and configuration when performing work on a live line." The Utility is implementing the recommendations made by the consultant. The CPUC, the U.S. Attorney's Office, and local Carmel officials are continuing to investigate the incident. It is reasonably possible that fines could be imposed on the Utility, or that other enforcement actions could be taken, in connection with this matter.

Pipeline Safety Enhancement Plan

On July 25, 2014, the Utility, together with the CPUC's ORA and TURN, requested that the CPUC approve a settlement agreement to resolve the Utility's PSEP Update application (submitted in October 2013). The settlement agreement proposes that the CPUC approve total PSEP-related revenue requirements (2012-2014) that reflect a $23 million reduction to expense funding, as compared to the Utility's request. For the three months ended June 30, 2014, the Utility recorded a charge against operating revenue to reflect the cumulative impact of this reduction. The settlement agreement does not propose any reductions to total PSEP capital costs of $766 million requested by the Utility in the PSEP Update application. The Utility previously has recorded cumulative charges of $549 million for PSEP-related capital costs that are expected to exceed the amount to be recovered. At June 30, 2014, approximately $400 million of PSEP-related capital costs is recorded in property, plant, and equipment on the Condensed Consolidated Balance Sheets. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected and to the extent the CPUC authorizes total capital costs that are lower than $766 million. The parties have requested the CPUC's approval of the settlement agreement by December 1, 2014. The Utility's ability to recover PSEP-related costs also could be affected by the final decisions to be issued in the CPUC's pending investigations discussed above.

Third-Party Liability Claims

The Utility has recorded cumulative charges of $565 million as its best estimate of probable loss for third-party claims related to the San Bruno accident. The Utility has settled substantially all third-party claims. Since the San Bruno accident, the Utility has made cumulative settlement payments of $532 million through June 30, 2014. In addition, the Utility has incurred cumulative expenses of $88 million for associated legal costs. The Utility has recognized cumulative insurance recoveries of $354 million for third-party claims and associated legal costs. The Utility believes it will recover a significant portion of its remaining costs through insurance, although the amount and timing of additional insurance recoveries are uncertain. The Utility has been engaged in settlement negotiations with its insurers regarding recovery of its remaining claims and costs.

Class Action Complaint

In August 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. The plaintiffs allege that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs seek restitution and disgorgement, as well as compensatory and punitive damages. PG&E Corporation and the Utility contest the plaintiffs' allegations. In May 2013, the court granted PG&E Corporation's and the Utility's request to dismiss the complaint on the grounds that the CPUC has exclusive jurisdiction to adjudicate the issues raised by the plaintiffs' allegations. The plaintiffs have appealed the court's ruling to the California Court of Appeal. PG&E Corporation and the Utility are unable to estimate the amount or range of reasonably possible losses, if any, that may be incurred in connection with this matter if the lower court's ruling is reversed.

Other Pending Lawsuits and Claims

At June 30, 2014, there were also five purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. The plaintiffs for four of these lawsuits filed a consolidated complaint with the San Mateo County Superior Court. Although the proceedings were stayed, the state court permitted the plaintiffs to amend the consolidated complaint to discuss recent events, including the federal criminal indictment discussed above. The plaintiffs in the consolidated state court lawsuits have requested that the judge lift the stay and allow the litigation to resume and PG&E Corporation, the Utility, and the individual defendants have requested that the judge continue the stay while the criminal proceeding is pending. On July 25, 2014, the judge issued a tentative ruling to lift the stay. At a hearing held on July 28, 2014, the judge stated that he would issue his final ruling on August 1, 2014. PG&E Corporation, the Utility, and the individual defendants have reserved their right to challenge all of the allegations in the amended complaint if the stay is lifted. The purported shareholder derivative lawsuit that was filed in the U.S. District Court for the Northern District of California remains stayed.

In February 2011, the Board of Directors of PG&E Corporation authorized PG&E Corporation to reject a demand made by another shareholder that the 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 of Directors members, officers, other employees, and third parties; and (3) adopt corporate governance initiatives and safety programs. The Board of Directors also reserved the right to commence further investigation or litigation regarding the San Bruno accident if the Board of Directors deems such investigation or litigation appropriate.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits will be resolved.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. Significant regulatory developments that have occurred since the 2013 Annual Report was filed with the SEC are discussed below.

2014 General Rate Case

In the GRC, the CPUC will determine the revenue requirements that the Utility is authorized to collect through rates from 2014 through 2016 to recover anticipated costs associated with its electric and natural gas distribution operations and electric generation operations. The revenue requirements requested by the Utility were based on the Utility's detailed expense and capital forecasts developed using operational plans that incorporate risk assessments and mitigation measures to address safety and security issues. The Utility also made various assumptions to develop these forecasts, including assumptions about depreciation methods and rates, cost escalation rates, and flow-through treatment of certain federal tax benefits.

On June 18, 2014, a proposed decision was issued that recommends an increase in 2014 revenue requirements of $453 million, or 6.8% over currently authorized amounts, compared to the $1,160 million, or 17.5%, increase requested by the Utility. The proposed decision recommends a total authorized revenue requirement of $7.1 billion for 2014 compared to the Utility's $7.8 billion request. The proposed decision recommends attrition increases of $322 million for 2015 and $371 million for 2016, compared to the Utility's requested attrition increases, as adjusted, of $436 million for 2015 and $486 million for 2016. The following table shows the differences between the Utility's requested increases in 2014 revenue requirements and the recommended amounts by line of business:

(in millions)	**Proposed Decision**	**Requested by the Utility**	**Difference**
Line of business			
Electric distribution	$ 127	$ 514	$ (387)
Gas distribution	242	446	(204)
Electric generation	84	200	(116)
Total revenue increase	**$ 453**	**$ 1,160**	**$ (707)**

Compared to the Utility's 2014 request, the proposed decision recommends reductions in funding for various safety, reliability, and customer service improvements across various parts of the business. The proposed decision recommends a depreciation rate-related expense increase of approximately $157 million as compared to the $492 million increase supported by the Utility's depreciation rate study. The Utility's analysis of the proposed decision also indicates that, if approved, the Utility's 2014 capital expenditures would be reduced from the $3.9 billion requested to approximately $3.5 billion. The proposed decision recommends authorizing a 2014 weighted average rate base of $20.5 billion as compared to the Utility's request of $21.0 billion, which reflects a reduction of approximately $400 million to exclude nuclear fuel inventory from rate base.

The proposed decision agrees with the Utility's request for new two-way balancing accounts to allow the Utility to recover costs associated with gas leak survey and repair, major emergencies, and certain new regulatory requirements related to nuclear operations and hydroelectric relicensing.

In July 2014, several parties, including the Utility, the CPUC's ORA, and TURN, submitted comments on the proposed decision. The CPUC may issue a final decision at its meeting on August 14, 2014. Upon receipt of a final decision, the Utility has been authorized to collect any final adopted increase in revenue requirements from January 1, 2014. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected if the Utility's actual costs differ from the amounts authorized in the final GRC decision.

2015 Gas Transmission and Storage Rate Case

As disclosed in the 2013 Annual Report, the Utility has requested that the CPUC approve an annual revenue requirement of $1.29 billion for 2015 for the Utility's anticipated costs of providing natural gas transmission and storage services, with attrition increases of $61 million in 2016 and $168 million in 2017. The CPUC has authorized the Utility's revenue requirement changes to become effective as of January 1, 2015, even if the final decision is issued after that date. The CPUC's current procedural schedule contemplates intervenor testimony to be submitted in August 2014, followed by evidentiary hearings to be held in October 2014, and a final decision to be issued in approximately March 2015.

The Utility has not requested authorization to recover approximately $150 million of costs it forecasts it will incur over the three-year period to pressure test pipelines placed into service after 1961 and perform remedial work associated with the Utility's pipeline corrosion control program. The Utility also has not requested authorization to recover costs it forecasts it will incur through 2017 to identify and remove encroachments from its gas transmission pipeline rights-of-way.

The Utility's continued use of regulatory accounting under GAAP (which enables it to account for the effects of regulation, including recording regulatory assets and liabilities) for gas transmission and storage service depends on its ability to recover its cost of service. If the Utility were unable to continue using regulatory accounting under GAAP, there would be differences in the timing of expense (or gain) recognition that could materially affect PG&E Corporation's and the Utility's future financial results.

FERC Transmission Owner Rate Cases

The Utility has two transmission owner rate cases pending at the FERC. With respect to the rate case that was filed in July 2013, the Utility, the FERC Trial Staff and all active intervening parties reached a settlement that was submitted to the FERC for approval in July 2014. The settlement, if approved, will increase the annual retail revenue requirement from $1,017 million to approximately $1,040 million, effective as of October 1, 2013. The Utility has been collecting revenues at the higher as-filed rates requested in the Utility's application. In future periods, the Utility will refund to customers the difference between revenues collected at the higher as-filed rates and the rates approved in the settlement. It is uncertain when the FERC will act on the settlement.

On July 30, 2014, the Utility filed an application with the FERC to request authorization of its proposed 2015 retail electric transmission revenue requirement of $1,366 million, a $326 million increase to the revenue requirements, if approved, described in the preceding paragraph. The Utility's 2015 cost forecasts reflect the continuing need to replace and modernize aging electric transmission infrastructure, to meet the need for increased capacity in the CAISO controlled grid, and to comply with new rules aimed at ensuring the physical and cyber security of the nation's electric system. The Utility forecasts that it will make investments of $975 million in 2014 and $1,125 million in 2015 in various capital projects. The proposed rate base in 2015 is forecast to be $5.12 billion compared to $4.57 billion in 2014. The Utility has requested that the FERC approve a 11.26% ROE. The Utility has requested the FERC to issue an order by September 2014 to accept the application and make the new rates effective on October 1, 2014, subject to refund pending a final decision by the FERC. It is anticipated that the rates will be suspended for five months and made effective on March 1, 2015, subject to refund.

Oakley Generation Facility

In December 2012, the CPUC approved an amended purchase and sale agreement between the Utility and a third-party developer that provides for the construction of a 586-megawatt natural gas-fired facility in Oakley, California. The CPUC authorized the Utility to recover the purchase price through rates. The CPUC's denial of various applications for rehearing that had been filed with respect to its decision was appealed to the California Court of Appeal. In February 2014, the California Court of Appeal issued a ruling that annulled the CPUC's decision after the court determined that the evidence presented did not support a finding of need for the Oakley facility. The Utility is considering its options.

Diablo Canyon Power Plant

The Utility filed an application with the NRC in 2009 to renew the operating licenses for the two operating units at Diablo Canyon. (The current licenses expire in 2024 and 2025.) In May 2011, after an earthquake and resulting tsunami that caused significant damage to the Fukushima-Dai-ichi nuclear facilities in Japan, the NRC granted the Utility's request to delay processing the Utility's application while certain advanced seismic studies were completed by the Utility. The Utility is currently assessing the data from recently completed advanced seismic studies along with other available seismic data and expects to provide its final seismic report to the NRC and the CPUC's Independent Peer Review Panel in the third quarter of 2014. (See the "2013 Annual Report" for additional information.)

Safety Enforcement Programs

On May 21, 2014, the CPUC began a rulemaking proceeding to implement a new electric safety citation program that would authorize CPUC staff to issue citations for safety violations and assess fines. California law enacted in 2013 requires the CPUC to implement a safety enforcement program for gas corporations by July 1, 2014 and for electric corporations by January 1, 2015. The rulemaking noted that the CPUC's current gas safety enforcement program appears to satisfy the law's requirements. (See "Natural Gas Matters – Other Enforcement Matters" above about the reports the Utility has filed to notify the CPUC staff of noncompliance with certain gas safety regulations.) As part of the rulemaking proceeding, the CPUC may modify the gas program and determine the timing and process for considering future modifications of the citation programs. The CPUC has indicated that it plans to implement an electric safety citation program before the end of 2014 and that it plans to decide which safety violations electric corporations will be required to self-report. Depending on the number and severity of reported violations, the Utility could be required to pay fines that, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

Electricity Rate Reform

New state legislation that became effective on January 1, 2014 (AB 327) repealed prior law that restricted the CPUC's ability to change residential electric rates, granting the CPUC authority to approve fixed charges to be collected from residential customers. In 2012, the CPUC began a rulemaking to examine residential rate design in California that, consistent with AB 327, allows the CPUC to simplify the rate structure and bring rates closer to actual costs. In February 2014, as ordered by the CPUC, the Utility submitted a long-term rate reform plan that proposes a fixed customer charge, gradual flattening of the tiered rate structure, and an optional time-of-use rate. The CPUC is expected to issue a final decision by the summer of 2015.

AB 327 also requires the CPUC to develop a new structure for net energy metering by December 31, 2015 that must be implemented no later than July 1, 2017. California's net energy metering program currently allows customers installing renewable distributed generation to receive bill credits for power delivered to the grid at their full retail rate. Increasing levels of self-generation of electricity by customers, coupled with net metering, has increased rates and shifted costs to remaining customers. AB 327 gives the CPUC new authority to reduce the cost shift associated with renewable distributed generation under the net energy metering rules. In July 2014, the CPUC began a rulemaking proceeding to develop a successor to the existing net energy metering program to comply with the requirements of AB 327. The CPUC's preliminary schedule contemplates a scoping memo to be issued in September 2014 and a proposed decision in the fall of 2015.

If the CPUC fails to adjust the Utility's rate design to bring rates closer to actual costs, or to adequately address the impact of increasing net energy metering and the growth of distributed generation, there will be increasing rate pressure on remaining customers. These increasing rate pressures could, in turn, cause more customers to seek alternative energy providers or sources, further exacerbating the Utility's risk it will not recover its costs to provide electric service.

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. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See "Risk Factors" in the 2013 Annual Report.)

Natural Gas Compressor Station Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment. At June 30, 2014, $170 million and $269 million was accrued in the Condensed Consolidated Balances Sheets for estimated undiscounted remediation costs associated with the Hinkley site and the Topock site, respectively. Costs associated with the Hinkley site are not recovered through rates. (See Note 10 of the Notes to the Condensed Consolidated Financial Statements.)

Clean Air Act

In June 2014, the EPA published draft federal regulations under section 111(d) of the Clean Air Act that are designed to reduce GHG emissions from existing fossil fuel-fired power plants by as much as 30 percent by 2030, compared with 2005 levels. As presently written, once the EPA has finalized regulations, all states will have one year to prepare, adopt, and submit to the EPA an implementation plan addressing how each state will control GHG emissions from existing power plants. The EPA is expected to issue final regulations by June 2015. It is uncertain whether and how these federal regulations would ultimately impact existing California state regulation, which currently requires, among other things, the gradual reduction of state-wide GHG emissions to the 1990 level by 2020. (As disclosed in the 2013 Annual Report, the Utility expects all costs and revenues associated with the state-wide, comprehensive "cap and trade" program to be passed through to customers).

CONTRACTUAL COMMITMENTS

PG&E Corporation and the Utility enter into contractual commitments in connection with future obligations that 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 purchases of fuel and transportation to support the Utility's generation activities. (Refer to the 2013 Annual Report and "Liquidity and Financial Resources" above.)

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, other than those discussed in Note 2 of the Notes to the Condensed Consolidated Financial Statements (PG&E Corporation's tax equity financing agreements) and Note 14 of the Notes to the Consolidated Financial Statements in the 2013 Annual Report (the Utility's commodity purchase agreements).

RISK MANAGEMENT ACTIVITIES

PG&E Corporation, mainly through its ownership of the Utility, and 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, electric transmission, natural gas transportation, and storage; emissions allowances and offset credits, 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 risk through risk management programs designed to support business objectives, discourage unauthorized risk-taking, reduce commodity cost volatility, and manage cash flows. The Utility uses derivative instruments only for non-trading purposes (i.e., risk mitigation) and not for speculative purposes. The Utility’s risk management activities include the use of energy and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases. These activities are discussed in detail in the 2013 Annual Report. There were no significant developments to the Utility and PG&E Corporation’s risk management activities during the six months ended June 30, 2014.

CRITICAL ACCOUNTING POLICIES

The preparation of the Condensed Consolidated Financial Statements in accordance with U.S. GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. PG&E Corporation and the Utility consider their accounting policies for regulatory assets and liabilities, loss contingencies associated with environmental remediation liabilities and legal and regulatory matters, asset retirement obligations, and pension and other postretirement benefits plans to be critical accounting policies. These policies are considered critical accounting policies due, in part, to their complexity and because their application is relevant and material to the financial position and results of operations of PG&E Corporation and the Utility, and because these policies require the use of material judgments and estimates. Actual results may differ materially from these estimates. These accounting policies and their key characteristics are discussed in detail in the 2013 Annual Report.

ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

Revenue Recognition Standard

In May 2014, the Financial Accounting Standards Board issued Accounting Standards Update No. 2014-09, *Revenue from Contracts with Customers*, which amends existing revenue recognition guidance . The accounting standards update will be effective on January 1, 2017. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures.

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which 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 losses, including penalties and fines, associated with various investigations and proceedings; forecasts of costs the Utility will incur to make safety and reliability improvements, including natural gas transmission costs that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "anticipate," "may," "should," "would," "could," "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 timing and outcome of the pending CPUC investigations and enforcement matters related to the Utility's natural gas system operating practices and the San Bruno accident, including the ultimate amount of fines the Utility will be required to pay to the State General Fund, the ultimate amount of costs the Utility will incur in its natural gas transmission business that it will not recover through rates, including the cost of any remedial actions the Utility may be ordered to perform;

- the timing and outcome of the federal criminal prosecution of the Utility, including the amount of any criminal fines or penalties imposed;

- whether the CPUC or a federal judge in the criminal case appoints a monitor to oversee the Utility's natural gas operations;

- whether additional investigations are commenced relating to the Utility's natural gas operating practices or specific incidents;

- whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by negative publicity about the San Bruno accident, the CPUC investigations, the criminal prosecution, the Utility's self-reports of noncompliance with certain natural gas safety regulations, and the ongoing work to remove encroachments from transmission pipeline rights-of-way;

- the outcomes of ratemaking proceedings, such as the 2014 GRC, the 2015 GT&S rate case, and the transmission owner rate cases and whether the cost and revenue forecasts assumed in such outcomes prove to be accurate;

- the amount and timing of additional common stock issuances by PG&E Corporation, the proceeds of which are contributed as equity to maintain the Utility's authorized capital structure as the Utility incurs charges and costs that it cannot recover through rates, including costs and fines associated with natural gas matters and the pending investigations;

- the outcome of future investigations, citations, or other enforcement proceedings, that may be commenced relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities; inspection and maintenance practices, customer billing and privacy, and physical and cyber security;

- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; the extent to which the Utility is able to recover environmental compliance and remediation costs in rates or from other sources; and the ultimate amount of environmental remediation costs the Utility incurs but does not recover, such as the remediation costs associated with the Utility's natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; and whether the Utility decides to request that the NRC resume processing the Utility's renewal application for the two Diablo Canyon operating licenses, and if so, whether the NRC grants the renewal;

- the impact of droughts or other weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, or vandalism (including cyber-attacks), and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or 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; and subject the Utility to third-party liability for property damage or personal injury, or result in the imposition of civil, criminal, or regulatory penalties on the Utility;

- the impact of environmental laws and regulations aimed at the reduction of carbon dioxide and GHGs, and whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations and the cost of renewable energy procurement;

- changes in customer demand for electricity and natural gas resulting from unanticipated population growth or decline in the Utility's service area; general and regional economic and financial market conditions; municipalization of the Utility's electric or gas distribution facilities; changing levels of "direct access" customers who procure electricity from alternative energy providers; changing levels of customers who purchase electricity from governmental bodies that act as "community choice aggregators"; the development of alternative energy technologies including self-generation, storage and distributed generation technologies; and changing levels of "core gas aggregation" customers who procure gas from core transport agents (alternative gas providers);

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, especially if the integration of renewable generation resources force conventional generation resource providers to curtail production, triggering "take or pay" provisions in the Utility's power purchase agreements;

- whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's operating systems;

- the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; including the timing and amount of insurance recoveries related to third party claims arising from the San Bruno accident;

- the ability of PG&E Corporation and the Utility to access capital markets and other sources of debt and equity financing in a timely manner on acceptable terms;

- changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose its investment grade credit ratings;

- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including 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 whether the ultimate outcomes of the matters discussed under "Natural Gas Matters" below affect the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation; and

- the impact of changes in GAAP, standards, rules, or policies, including those related to regulatory accounting, and the impact of changes in their interpretation or application.

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, results of operations, and cash flows, see "Risk Factors" in the 2013 Annual Report and "Item 1A. Risk Factors" below. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

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 commodity 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 the section above entitled "Risk Management Activities" in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.)

ITEM 4. CONTROLS AND PROCEDURES

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of June 30, 2014, 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 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 Securities Exchange Act of 1934 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 June 30, 2014 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

In addition to the following legal proceedings, PG&E Corporation and the Utility are involved in various legal proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's contingencies, see Note 10 of the Notes to the Condensed Consolidated Financial Statements.

Diablo Canyon Nuclear Power Plant

For more information regarding the status of the 2003 settlement agreement between the Central Coast Regional Water Quality Control Board and the Utility, see "Part I, Item 3. Legal Proceedings" in the 2013 Annual Report.

Criminal Indictment

On July 30, 2014, the U.S. Attorney's Office for the Northern District of California filed a 28-count superseding criminal indictment against the Utility in federal district court replacing the indictment that had been filed on April 1, 2014. The superseding indictment alleges 27 felony counts (increased from 12 counts alleged in the original indictment) charging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record keeping, pipeline integrity management, and identification of pipeline threats. The superseding indictment also includes one felony count charging that the Utility obstructed the NTSB's investigation of the San Bruno accident in violation of a federal statute prohibiting obstruction of a federal agency's proceedings. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also alleges a maximum alternative fine under the Alternative Fines Act which states, in part: "If any person derives pecuniary gain from the offense, or if the offense results in pecuniary loss to a person other than the defendant, the defendant may be fined not more than the greater of twice the gross gain or twice the gross loss, unless imposition of a fine under this subsection would unduly complicate or prolong the sentencing process." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion. The Utility continues to believe that criminal charges are not merited and that it did not knowingly and willfully violate minimum safety standards under the Natural Gas Pipeline Safety Act or obstruct the NTSB's investigation, as alleged in the superseding indictment. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their condensed consolidated financial statements as such amounts are not probable. The Utility will appear in court at a status conference that is scheduled to be held on August 18, 2014. See the discussion in "Item 1A. Risk Factors" below.

Pending CPUC Investigations

There are three CPUC investigative enforcement proceedings pending against the Utility related to the Utility's natural gas operations and the San Bruno accident. Evidentiary hearings and briefing on the issue of alleged violations have been completed in each of these investigations. The CPUC has stated that it is prepared to impose significant penalties on the Utility if the CPUC determines that the Utility violated applicable laws, rules, and orders. The ALJs who are presiding over the investigations are expected to issue one or more decisions to address the violations that they have determined the Utility committed and to impose penalties. It is uncertain when these decisions will be issued. The SED has recommended that the CPUC impose what the SED characterizes as a penalty of $2.25 billion on the Utility, consisting of a $300 million fine payable to the State General Fund and $1.95 billion of non-recoverable costs.

For additional information, see the discussion entitled "Natural Gas Matters – Pending CPUC Investigations" above in Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 10 of the Notes to the Condensed Consolidated Financial Statements. In addition, see "Part I, Item 3. Legal Proceedings" in the 2013 Annual Report 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 March 31, 2014.

Litigation Related to the San Bruno Accident and Natural Gas Spending

At June 30, 2014, there were five purported shareholder derivative lawsuits outstanding against PG&E Corporation and the Utility seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. The plaintiffs for four of these lawsuits filed a consolidated complaint with the San Mateo County Superior Court. Although the proceedings were stayed, the state court permitted the plaintiffs to amend the consolidated complaint to discuss recent events, including the federal criminal indictment discussed above. The plaintiffs in the consolidated state court lawsuits have requested that the judge lift the stay and allow the litigation to resume and PG&E Corporation, the Utility, and the individual defendants have requested that the judge continue the stay while the criminal proceeding is pending. On July 25, 2014, the judge issued a tentative ruling to lift the stay. At a hearing held on July 28, 2014, the judge stated that he would issue his final ruling on August 1, 2014. PG&E Corporation, the Utility, and the individual defendants have reserved their right to challenge all of the allegations in the amended complaint if the stay is lifted. The purported shareholder derivative lawsuit that was filed in the U.S. District Court for the Northern District of California remains stayed.

In addition, on August 23, 2012, a complaint was filed in the San Francisco Superior Court against PG&E Corporation and the Utility (and other unnamed defendants) by individuals who seek certification of a class consisting of all California residents who were customers of the Utility between 1997 and 2010, with certain exceptions. The plaintiffs allege that the Utility collected more than $100 million in customer rates from 1997 through 2010 for the purpose of various safety measures and operations projects but instead used the funds for general corporate purposes such as executive compensation and bonuses. PG&E Corporation and the Utility contest the allegations.

For additional information regarding these matters as well as third-party liability claims related to the San Bruno Accident, see the discussion entitled “Natural Gas Matters” above in Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations and in Note 10 of the Notes to the Condensed Consolidated Financial Statements. In addition, see “Part I, Item 3. Legal Proceedings” in the 2013 Annual Report 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 March 31, 2014.

Gas Safety Citation Program

The SED has authority to issue citations and impose fines on California gas corporations, such as the Utility, for violations of certain state and federal regulations that relate to the safety of natural gas facilities and operating practices. The California gas corporations are required to inform the SED of any self-identified or self-corrected violations of these regulations. The SED has discretion to impose fines or take other enforcement action to address a violation, based on the totality of the circumstances. The SED can consider various factors in determining whether to impose fines and the amount of fines, including the severity of the safety risk associated with each violation, the number and duration of the violations, whether the violation was self-reported, and whether corrective actions were taken. The SED has imposed fines ranging from $50,000 to $16.8 million in connection with several of the Utility’s self-reports.

At June 30, 2014, the Utility has submitted about 65 self-reports (plus some follow-up reports) that the SED has not yet addressed. In addition, in July 2014, the Utility reported that it discovered that, contrary to its procedures, employees who perform work to fuse plastic pipes together had completed only part of their requisite re-qualification. The Utility believes that this issue does not constitute a safety concern as every plastic pipe installed in the field is tested on site and under pressure before being put into service. The Utility suspended non-emergency plastic fusion work until employees who perform this work undergo proper re-qualifications.

The Utility believes it is probable that the SED will impose fines or take other enforcement action with respect to some of the Utility’s self-reports in the future. In addition, the SED has been conducting numerous compliance audits of the Utility’s operating practices and has informed the Utility that the SED’s audit findings include several allegations of noncompliant practices. It is reasonably possible that the SED will impose fines with respect to its audit findings. The Utility has been taking corrective actions in response to these matters.

For additional information, see the discussion entitled “Natural Gas Matters – Other Enforcement Matters” above in Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations and in Note 10 of the Notes to the Condensed Consolidated Financial Statements. In addition, see “Part I, Item 3. Legal Proceedings” in the 2013 Annual Report 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 March 31, 2014.

ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see the section of the 2013 Annual Report entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Cautionary Language Regarding Forward-Looking Statements."

PG&E Corporation's and the Utility's reputations have been significantly affected by the negative publicity about the federal criminal indictment of the Utility for alleged violations of the federal Pipeline Safety Act and for allegedly obstructing the NTSB's investigation of the San Bruno accident. Their reputations could be further harmed by the eventual outcome of the pending CPUC investigations and if additional enforcement action is taken with respect to other natural gas operating practices or incidents. The outcome of these matters, including the amount of fines and penalties that may be imposed on the Utility and the ultimate amount of unrecoverable costs the Utility incurs in connection with its natural gas operations could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations and cash flows .

The reputations of PG&E Corporation and the Utility have suffered as a result of the extensive media coverage of the federal criminal prosecution of the Utility and allegations that the Utility improperly communicated with the CPUC regarding the substance of the pending CPUC investigations. (See "Natural Gas Matters" above.) Media coverage of future developments in the criminal prosecution and following the issuance of the decisions in the three pending CPUC investigations may cause further reputational harm. In addition, their reputations could suffer further depending on the outcome of the other matters relating to the Utility's natural gas operations as discussed under "Natural Gas Matters – Other Enforcement Matters" above. While the CPUC investigations remain unresolved and as personnel changes occur at the CPUC, it can become increasingly difficult to estimate how these other matters will be addressed. If events or developments occur that further harm PG&E Corporation's and the Utility's reputations, the additional reputational harm could have a negative influence on how these other matters are addressed. Additional reputational harm also could negatively influence the regulatory decision-making process in the Utility's ratemaking proceedings pending at the CPUC, such as the 2014 GRC and the GT&S rate case.

Continuing negative publicity and uncertainty about the outcome of the CPUC investigations and the criminal proceeding may cause investors to question management's ability to repair the reputational harm that PG&E Corporation and the Utility have suffered, resulting in an adverse impact on the market price of PG&E Corporation common stock. The issuance of common stock by PG&E Corporation to fund the Utility's unrecovered costs has materially diluted PG&E Corporation's EPS. Additional share issuances following a declining stock price would cause further dilution.

In addition to the reputational harm associated with these matters, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected by the outcome of these matters. The final decisions to be issued in the CPUC investigations may order the Utility to pay fines that materially exceed the amount previously accrued. The ultimate amount of pipeline-related costs that the Utility incurs but does not recover through rates will be affected by the final decisions in the CPUC investigations, the outcome of pending ratemaking proceedings, the extent to which the scope and timing of planned pipeline work changes, and whether actual costs exceed forecasts. In addition, if the Utility is convicted of the criminal charges in the federal prosecution and the jury finds that the criminal conduct caused a pecuniary gain or loss, a material amount of fines could be imposed on the Utility. Although the maximum statutory fine for each of the 28 counts charged in the superseding indictment is $500,000 (for a total of $14 million), the U.S. Attorney is seeking an alternative fine based on the greater of twice the gross gain the Utility allegedly derived or twice the gross loss allegedly caused. The superseding indictment alleges that the Utility derived gross gains of approximately $281 million and caused gross losses of approximately $565 million. Based on these allegations, the maximum alternative fine would be approximately $1.13 billion.

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

During the quarter ended June 30, 2014, PG&E Corporation made equity contributions totaling $330 million to the Utility in order to maintain the 52% common equity component of its CPUC-authorized capital structure. Neither PG&E Corporation nor the Utility made any sales of unregistered equity securities during the quarter ended June 30, 2014.

Issuer Purchases of Equity Securities

During the quarter ended June 30, 2014, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended June 30, 2014, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

ITEM 5. OTHER INFORMATION

Since May 1, 2014, PG&E Corporation has made equity contributions to the Utility totaling $370 million, including equity contributions of $125 million that were made on July 30, 2014.

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 six months ended June 30, 2014 was 2.24. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the six months ended June 30, 2014 was 2.21. 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 No. 333-193879.

PG&E Corporation's earnings to fixed charges ratio for the six months ended June 30, 2014 was 2.21. 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. 333-193880.

ITEM 6. EXHIBITS

4.1	Twenty-Second Supplemental Indenture, dated as of May 12, 2014, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due May 11, 2015 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 12, 2014 (File No. 12348), Exhibit 4.1)
*10.1	PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 (incorporated by reference to PG&E Corporation's Registration Statement on Form S-8, No. 333-195902, Exhibit 99)
*10.2	PG&E Corporation Officer Severance Policy, as amended effective as of May 12, 2014
*10.3	Form of Restricted Stock Unit Agreement for 2014 grants to directors under the PG&E Corporation 2014 Long-Term Incentive Plan
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
31.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

anagement 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.

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

DINYAR B. MISTRY

Dinyar B. Mistry
Vice President, Chief Financial Officer and Controller
(duly authorized officer and principal financial officer)

Dated: July 31, 2014

EXHIBIT INDEX

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101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

* Management contract or compensatory agreement.

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

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

	Six Months Ended June 30,	Year Ended December 31,				
	2014	2013	2012	2011	2010	2009
Earnings:						
Net income	$ 478	$ 866	$ 811	$ 845	$ 1,121	$ 1,250
Income tax provision	210	326	298	480	574	482
Fixed charges	553	971	891	880	799	817
Total earnings	**$ 1,241**	**$ 2,163**	**$ 2,000**	**$ 2,205**	**$ 2,494**	**$ 2,549**
Fixed charges:						
Interest on short-term borrowings and long-term debt, net	$ 529	$ 917	$ 834	$ 824	$ 731	$ 754
Interest on capital leases	3	7	9	16	18	19
AFUDC debt	21	47	48	40	50	44
Total fixed charges	**$ 553**	**$ 971**	**$ 891**	**$ 880**	**$ 799**	**$ 817**
Ratios of earnings to fixed charges	**2.24**	**2.23**	**2.24**	**2.51**	**3.12**	**3.12**

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. Fixed charges exclude interest on tax liabilities.

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

	Six Months Ended June 30,	Year ended December 31,				
	2014	2013	2012	2011	2010	2009
Earnings:						
Net income	$ 478	$ 866	$ 811	$ 845	$ 1,121	$ 1,250
Income tax provision	210	326	298	480	574	482
Fixed charges	553	971	891	880	799	817
Total earnings	**$ 1,241**	**$ 2,163**	**$ 2,000**	**$ 2,205**	**$ 2,494**	**$ 2,549**
Fixed charges:						
Interest on short-term borrowings and long-term debt, net	$ 529	$ 917	$ 834	$ 824	$ 731	$ 754
Interest on capital leases	3	7	9	16	18	19
AFUDC debt	21	47	48	40	50	44
Total fixed charges	**$ 553**	**$ 971**	**$ 891**	**$ 880**	**$ 799**	**$ 817**
Preferred stock dividends:						
Tax deductible dividends	$ 4	$ 9	$ 9	$ 9	$ 9	$ 9
Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements	4	7	7	8	7	7
Total preferred stock dividends	**8**	**16**	**16**	**17**	**16**	**16**
Total combined fixed charges and preferred stock dividends	**$ 561**	**$ 987**	**$ 907**	**$ 897**	**$ 815**	**$ 833**
Ratios of earnings to combined fixed charges and preferred stock dividends	**2.21**	**2.19**	**2.21**	**2.46**	**3.06**	**3.06**

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. “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.

EXHIBIT 12.3
PG&E CORPORATION
COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES

	Six Months Ended June 30,	Year Ended December 31,				
	2014	2013	2012	2011	2010	2009
Earnings:						
Net income	$ 501	$ 828	$ 830	$ 858	$ 1,113	$ 1,234
Income tax provision	195	268	237	440	547	460
Fixed charges	570	1,012	931	919	850	877
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	(8)	(16)	(15)	(17)	(16)	(16)
Total earnings	**$ 1,258**	**$ 2,092**	**$ 1,983**	**$ 2,200**	**$ 2,494**	**$ 2,555**
Fixed charges:						
Interest on short-term borrowings and long-term debt, net	$ 538	$ 942	$ 859	$ 846	$ 766	$ 798
Interest on capital leases	3	7	9	16	18	19
AFUDC debt	21	47	48	40	50	44
Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries	8	16	15	17	16	16
Total fixed charges	**$ 570**	**$ 1,012**	**$ 931**	**$ 919**	**$ 850**	**$ 877**
Ratios of earnings to fixed charges	**2.21**	**2.07**	**2.13**	**2.39**	**2.93**	**2.91**

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.

Exhibit 10.2

PG&E CORPORATION
2012 OFFICER SEVERANCE POLICY
(Amended effective as of May 12, 2014)

1. Purpose. This is the controlling and definitive statement of the Officer Severance Policy of PG&E Corporation ("Policy"). Since Officers are employed at the will of PG&E Corporation ("Corporation") or a participating employer ("Employer"), their employment may be terminated at any time, with or without cause. A list of Employers is attached hereto as Appendix A. The Policy became effective March 1, 2012, and provides Officers of the Corporation and Employers in Officer Compensation Bands I through V ("Officers") with severance benefits if their employment is terminated, and the Officer is not eligible for severance benefits under the predecessor PG&E Corporation Officer Severance Policy (the "Predecessor Policy"), which was first adopted effective November 1, 1998. [1] The Policy's definition of Change in Control was amended effective May 12, 2014. [2] Severance benefits for officers not covered by this Policy (or the Predecessor Policy) will be provided under policies or programs developed by the appropriate lines of business in consultation with and with the approval by the Senior Human Resources Officer of the Corporation. For the avoidance of doubt, revisions made to this Policy relating to Code Section 409A (defined below), apply to all Officers including those that may be covered under prior provisions of the Policy as required by Section 6 hereof.

The purpose of the Policy is to attract and retain senior management by defining terms and conditions for severance benefits, to provide severance benefits that are part of a competitive total compensation package, to provide consistent treatment for all terminated officers, and to minimize potential litigation costs associated with Officer termination of employment.

2. Termination of Employment Not Following a Change in Control or Potential Change in Control.

(a) Corporation or Employer's Obligations. If the Corporation or an Employer exercises its right to terminate an Officer's employment without cause and such termination does

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1 Severance benefits for Officers who are currently covered by an employment agreement will continue to be provided solely under such agreements until their expiration at which time this Policy will become effective for such Officers. Any Officer's waiver of benefits under this Policy shall take precedence over the terms of this Policy. If an employee becomes a covered Officer under this Policy as a result of a promotion, and if such Officer was then covered by a severance arrangement subject to Section 409A of the Internal Revenue Code of 1986 ("Code Section 409A"), the severance benefits under this Policy provided to such person shall comply with the time and form of payment provisions of such prior severance arrangement, to the extent required by Code Section 409A.

Officers subject to the Predecessor Policy as of February 29, 2012 will continue to be subject to the terms of that Prececessor Policy until three years after receiving notice of the adoption of this Policy and its terms, to the extent that becoming subject to this Policy would reduce such officers' aggregate level of benefits, as per Section 6 of the Predecessor Policy.

2 Officers described in the second paragraph of the preceding footnote and officers subject to this Policy as of May 11, 2014 will continue to be subject to the definition of Change in Control in the Predecessor Policy or the Policy, as applicable, in effect on May 11, 2014, until three years after receiving notice of the adoption of the revised definition of Change in Control, to the extent that becoming subject to such revision would reduce such officers' aggregate level of benefits, as per Section 6 of the Predecessor Policy and this Policy.

not entitle Officer to payments under Section 3, the Officer shall be given thirty (30) days' advance written notice or pay in lieu thereof (which shall be paid in a lump sum together with the payment described in Section 2(a)(1) below). Except as provided in Section 2(b) below, in consideration of the Officer's agreement to the obligations described in Section 2(d) below and to the arbitration provisions described in Section 12 below, the following payments and benefits shall also be provided to Officer following Officer's separation from service (within the meaning of Code Section 409A): [3]

(1) A lump sum severance payment equal to: 1/12 (the sum of the Officer's annual base compensation and the Officer's Short-Term Incentive Plan target award at the time of his or her termination) times twelve ("Severance Multiple"). Annual base compensation shall mean the Officer's monthly base pay for the month in which the Officer is given notice of termination, multiplied by 12. The payment described in this Section 2(a)(1) shall be made in a single lump sum as soon as practicable following the date the release of claims described in Section 2(d)(1) becomes effective, provided that payment shall in no event be made later than the 15th day of the third month following the later of the end of the calendar year or the Corporation's taxable year in which the Officer's separation from service occurs.

(2) Except as otherwise set forth in the applicable award agreement or as otherwise required by applicable law, the equity-based incentive awards granted to Officer under the Corporation's Long-Term Incentive Program which have not yet vested as of the date of termination will continue to vest over a period of months equal to the Severance Multiple after the date of termination as if the Officer had remained employed for such period. Except as otherwise set forth in the applicable award agreement, for vested stock options as of the date of termination, the Officer shall have the right to exercise such stock options at any time within their respective terms or within five years after termination, whichever is shorter. Except as otherwise set forth in the applicable award agreement, for stock options that vest during a period of months equal to the Severance Multiple, the Officer shall have the right to exercise such options at any time within one year after termination, subject to the term of the options. Except as otherwise set forth in the applicable award agreement, any unvested equity-based incentive awards remaining at the end of such period shall be forfeited;

(3) For Officers in Officer Bands I, II or III, two thirds of the unvested Company stock units in the Officer's account in the Corporation's Deferred Compensation Plan for Officers which were awarded in connection with the Executive Stock Ownership Program requirements (" SISOPs ") shall vest upon the Officer's termination, and one third shall be forfeited. For Officers in Officer Bands IV and V, one third of any unvested SISOPs shall vest upon the Officer's termination, and two thirds shall be forfeited. Unvested stock units attributable to SISOPs which become vested under this provision shall be distributed to Officer in accordance with the Deferred Compensation Plan after such stock units vest;

(4) Officer shall be entitled to receive a lump sum cash payment equal to the estimated value of 18 months'of COBRA premiums for the Officer, based on the Officer's benefit levels at the time of termination (with such payment subject to taxation under applicable law);

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3 Any payments made hereunder shall be less applicable taxes.

(5) To the extent not theretofore paid or provided, the Officer shall be paid or provided with any other amounts or benefits required to be paid or provided or which the Officer is eligible to receive under any plan, contract or agreement of the Corporation or Employer;

(6) Such career transition services as the Corporation's Senior Human Resources Officer shall determine is appropriate (if any), provided that payment of such services will only be made to the extent the Officer actually incurs an expense and then only to the extent incurred and paid within the time limit set forth in Treasury Regulation Section 1.409A-1(b)(9)(v)(E). Any such services, to the extent they are not exempt under Treasury Regulation Section 1.409A-1(b)(9)(v)(A) or (D), shall be structured to comply with the requirements of Treasuary Regulation Section 1.409A-3(i)(1)(iv) and, if applicable, shall be subject to the six-month delay described in Code Section 409A(a)(2)(B)(i).

(7) All acts required of the Employer under the Policy may be performed by the Corporation for itself and the Employer, and the costs of the Policy may be equitably apportioned by the Administrator among the Corporation and the other Employers. The Corporation shall be responsible for making payments and providing benefits pursuant to this Policy for Officers employed by the Corporation. Whenever the Employer is permitted or required under the terms of the Policy to do or perform any act, matter or thing, it shall be done and performed by any Officer or employee of the Employer who is thereunto duly authorized by the board of directors of the Employer. Each Employer shall be responsible for making payments and providing benefits pursuant to the Policy on behalf of its Officers or for reimbursing the Corporation for the cost of such payments or benefits, as determined by the Corporation in its sole discretion. In the event the respective Employer fails to make such payment or reimbursement, an Officer's (or other payee's) sole recourse shall be against the respective Employer, and not against the Corporation ;

(b) Remedies . An Officer shall be entitled to recover damages for late or nonpayment of amounts to which the Officer is entitled hereunder. The Officer shall also be entitled to seek specific performance of the obligations and any other applicable equitable or injunctive relief.

(c) Section 2(a) shall not apply in the event that an Officer's employment is terminated "for cause." Except as used in Section 3 of this Policy, "for cause" means that the Corporation, in the case of an Officer employed by the Corporation, or Employer in the case of an Officer employed by an Employer, acting in good faith based upon information then known to it, determines that the Officer has engaged in, committed, or is responsible for (1) serious misconduct, gross negligence, theft, or fraud against the Corporation and/or an Employer; (2) refusal or unwillingness to perform his duties; (3) inappropriate conduct in violation of Corporation's equal employment opportunity policy; (4) conduct which reflects adversely upon, or making any remarks disparaging of, the Corporation, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries; (5) insubordination; (6) any willful act that is likely to have the effect of injuring the reputation, business, or business relationship of the Corporation or its subsidiaries or affiliates; (7) violation of any fiduciary duty; or (8) breach of any duty of loyalty; or (9) any breach of the restrictive covenants contained in Section 2(d) below. Upon termination "for cause," the Corporation, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries shall have no liability to the Officer other than for accrued salary, vacation benefits, and any vested rights the Officer may have under the benefit and compensation plans in which the Officer participates and under the general terms and conditions of the applicable plan.

(d) Obligations of Officer .

(1) Release of Claims . There shall be no obligation to commence the payment of the amounts and benefits described in Section 2(a) until the latter of (1) the delivery by Officer to the Corporation a fully executed comprehensive general release of any and all known or unknown claims that he or she may have against the Corporation, its Board of Directors, Officers, or employees, or its affiliates or subsidiaries and a covenant not to sue in the form prescribed by the Administrator, and (2) the expiration of any revocation period set forth in the release. The Corporation shall promptly furnish such release to Officer in connection with the Officer's separation from service, and such release must be executed by Officer and become effective during the period set forth in the release as a condition to Officer receiving the payments and benefits described in Section 2(a).

(2) Covenant Not to Compete . (i) During the period of Officer's employment with the Corporation or its subsidiaries and for a period of twelve (12) months thereafter (the " Restricted Period "), Officer shall not, in any county within the State of California or in any city, county or area outside the State of California within the United States or in the countries of Canada or Mexico, directly or indirectly, whether as partner, employee, consultant, creditor, shareholder, or other similar capacity, promote, participate, or engage in any activity or other business competitive with the Corporation's business or that of any of its subsidiaries or affiliates, without the prior written consent of the Corporation's Chief Executive Officer. Notwithstanding the foregoing, Officer may have an interest in any public company engaged in a competitive business so long as Officer does not own more than 2 percent of any class of securities of such company, Officer is not employed by and does not consult with, or becomes a director of, or otherwise engage in any activities for, such competing company.

a. The Corporation and its subsidiaries presently conduct their businesses within each county in the State of California and in areas outside California that are located within the United States, and it is anticipated that the Corporation and its subsidiaries will also be conducting business within the countries of Canada and Mexico. Such covenants are necessary and reasonable in order to protect the Corporation and its subsidiaries in the conduct of their businesses. To the extent that the foregoing covenant or any provision of this Section 2(d)(2)a shall be deemed illegal or unenforceable by a court or other tribunal of competent jurisdiction with respect to (i) any geographic area, (ii) any part of the time period covered by such covenant, (iii) any activity or capacity covered by such covenant, or (iv) any other term or provision of such covenant, such determination shall not affect such covenant with respect to any other geographic area, time period, activity or other term or provision covered by or included in such covenant.

(3) Soliciting Customers and Employees . During the Restricted Period, Officer shall not, directly or indirectly, solicit or contact any customer or any prospective

customer of the Corporation or its subsidiaries or affiliates for any commercial pursuit that could be reasonably construed to be in competition with the Corporation, or induce, or attempt to induce, any employees, agents or consultants of or to the Corporation or any of its subsidiaries or affiliates to do anything from which Officer is restricted by reason of this covenant nor shall Officer, directly or indirectly, offer or aid to others to offer employment to, or interfere or attempt to interfere with any employment, consulting or agency relationship with, any employees, agents or consultants of the Corporation, its subsidiaries and affiliates, who received compensation of $75,000 or more during the preceding six (6) months, to work for any business competitive with any business of the Corporation, its subsidiaries or affiliates.

(4) Confidentiality. Officer shall not at any time (including after termination of employment) divulge to others, use to the detriment of the Corporation or its subsidiaries or affiliates, or use in any business competitive with any business of the Corporation or its subsidiaries or affiliates any trade secret, confidential or privileged information obtained during his employment with the Corporation or its subsidiaries or affiliates, without first obtaining the written consent of the Corporation's Chief Executive Officer. This paragraph covers but is not limited to discoveries, inventions (except as otherwise provided by California law), improvements, and writings, belonging to or relating to the affairs of the Corporation or of any of its subsidiaries or affiliates, or any marketing systems, customer lists or other marketing data. Officer shall, upon termination of employment for any reason, deliver to the Corporation all data, records and communications, and all drawings, models, prototypes or similar visual or conceptual presentations of any type, and all copies or duplicates thereof, relating to all matters contemplated by this paragraph.

(5) Assistance in Legal Proceedings. During the Restricted Period, Officer shall, upon reasonable notice from the Corporation, furnish information and proper assistance (including testimony and document production) to the Corporation as may be reasonably required by the Corporation in connection with any legal, administrative or regulatory proceeding in which it or any of its subsidiaries or affiliates is, or may become, a party, or in connection with any filing or similar obligation of the Corporation imposed by any taxing, administrative or regulatory authority having jurisdiction, provided, however, that the Corporation shall pay all reasonable expenses incurred by Officer in complying with this paragraph within 60 days after Officer incurs such expenses.

(6) Remedies. Upon Officer's failure to comply with the provisions of this Section 2(d), the Corporation shall have the right to immediately terminate any unpaid amounts or benefits described in Section 2(a) to Officer. In the event of such termination, the Corporation shall have no further obligations under this Policy and shall be entitled to recover damages. In the event of an Officer's breach or threatened breach of any of the covenants set forth in this Section 2(d), the Corporation shall also be entitled to specific performance by Officer of any such covenant and any other applicable equitable or injunctive relief.

3. Termination of Employment Following a Change in Control or Potential Change in Control.

(a) If an Executive Officer's employment by the Corporation or any subsidiary or successor of the Corporation shall be subject to an Involuntary Termination within the Covered

Period, then the provisions of this Section 3 instead of Section 2 shall govern the obligations of the Corporation as to the payments and benefits it shall provide to the Executive Officer. In the event that Executive Officer's employment with the Corporation or an employing subsidiary is terminated under circumstances which would not entitle Executive Officer to payments under this Section 3, Executive Officer shall only receive such benefits to which he is entitled under Section 2, if any. In no event shall Executive Officer be entitled to receive termination benefits under both this Section 3 and Section 2.

All the terms used in this Section 3 shall have the following meanings:

(1) " Affiliate " shall mean any entity which owns or controls, is owned or is under common ownership or control with, the Corporation.

(2) " Cause " shall mean (i) the willful and continued failure of the Executive Officer to perform substantially the Executive Officer's duties with the Corporation or one of its affiliates (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive Officer by the Board of Directors or the Chief Executive Officer of the Corporation which specifically identifies the manner in which the Board of Directors or Chief Executive Officer believes that the Executive Officer has not substantially performed the Executive Officer's duties; or (ii) the willful engaging by the Executive Officer in illegal conduct or gross misconduct which is materially demonstrably injurious to the Corporation.

For purposes of the provision, no act or failure to act, on the part of the Executive Officer, shall be considered "willful" unless it is done, or omitted to be done, by the Executive Officer in bad faith or without reasonable belief that the Executive Officer's action or omission was in the best interests of the Corporation. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board of Directors or upon the instructions of the Chief Executive Officer or a senior officer of the Corporation or based upon the advice of counsel for the Corporation shall be conclusively presumed to be done, or omitted to be done, by the Executive Officer in good faith and in the best interests of the Corporation. The cessation of employment of the Executive Officer shall not be deemed to be for Cause unless and until there shall have been delivered to the Executive Officer a copy of a resolution duly adopted by the affirmative vote of not less than three-quarters of the entire membership of the Board of Directors at a meeting of the Board of Directors called and held for such purpose (after reasonable notice is provided to the Executive Officer and the Executive Officer is given an opportunity, together with counsel, to be heard before the Board of Directors), finding that, in the good faith opinion of the Board of Directors, the Executive Officer is guilty of the conduct described in subparagraph (i) or (ii) above, and specifying the particulars thereof in detail.

(3) " Change in Control " shall mean the occurrence of any of the following:

a. any "person" (as such term is used in Sections 13(d) and 14(d) of the Securities Exchange Act of 1934 ("Exchange Act"), but excluding any benefit plan for employees or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the "beneficial owner" (as defined in Rule 13d-3 promulgated under the Exchange Act) of securities of the Corporation representing thirty percent (30%) or more of the combined voting power of the Corporation's then outstanding voting securities; or

b. during any two consecutive years, individuals who at the beginning of such a period constitute the Board of Directors of the Corporation ("Board") cease for any reason to constitute at least a majority of the Board, unless the election, or the nomination for election by the shareholders of the Corporation, of each new member of the Board ("Director") was approved by a vote of at least two-thirds ($^{2}/_{3}$) of the Directors then still in office (1) who were Directors at the beginning of the period or (2) whose election or nomination was previously so approved; or

c. the consummation of any consolidation or merger of the Corporation other than a merger or consolidation which would result in the holders of the voting securities of the Corporation outstanding immediately prior thereto continuing to directly or indirectly hold at least seventy percent (70%) of the Combined Voting Power of the Corporation, the surviving entity in the merger or consolidation or the parent of such surviving entity outstanding immediately after the merger or consolidation; or

d. (1) the consummation of any sale, lease, exchange or other transfer (in one or a series of related transactions) of all or substantially all of the assets of the Corporation or (2) the approval of the shareholders of the Corporation of a plan of liquidation or dissolution of the Corporation.

(4) " Change in Control Date " shall mean the date on which a Change in Control occurs.

(5) " Combined Voting Power " shall mean the combined voting power of the Corporation's or other relevant entity's then outstanding voting securities.

(6) " Covered Period " shall mean the period commencing with the Change in Control Date and terminating two (2) years following said commencement; provided, however, that if a Change in Control occurs and Executive Officer's employment with the Corporation or the employing subsidiary is subject to an Involuntary Termination before the Change in Control Date but on or after a Potential Change in Control Date, and if it is reasonably demonstrated by the Executive Officer that such termination (i) was at the request of a third party who has taken steps reasonably calculated to effect a Change in Control, or (ii) otherwise arose in connection with or in anticipation of a Change in Control, then the Covered Period shall mean, as applied to Executive Officer, the two-year period beginning on the date immediately before the Potential Change in Control Date.

(7) " Disability " shall mean the absence of the Executive Officer from the Executive Officer's duties with the Corporation or the employing subsidiary on a full-time basis for 180 consecutive business days as a result of incapacity due to physical or mental illness which is determined to be total and permanent by a physician selected by the Corporation or its insurers and acceptable to the Executive Officer or the Executive Officer's legal representative.

(8) " Executive Officer " shall mean officers in Officer Compensation Bands I through II.

(9) "Good Reason" shall mean any one or more of the following which takes place within the Covered Period:

a. A material diminution in the Executive Officer's base compensation;

b. A material diminution in the Executive Officer's authority, duties, or responsibilities;

c. A material diminution in the authority, duties, or responsibilities of the supervisor to whom the Executive Officer is required to report, including a requirement that the Executive Officer report to a corporate officer or employee instead of reporting directly to the Board of Directors of the Corporation (in the case of an Executive Officer reporting to such Board of Directors);

d. A material diminution in the budget over which the Executive Officer retains authority;

e. A material change in the geographic location at which the Executive Officer must perform the services; or

f. Any other action or inaction that constitutes a material breach by the Corporation of this Policy;

provided, however, that the Executive Officer must provide notice to the Corporation of the existence of the applicable condition described in this Section 3(a)(9) within 90 days of the initial existence of the condition, upon the notice of which the Corporation shall have 30 days during which it may remedy the condition and, if remedied, Good Reason shall not exist.

(10) "Involuntary Termination" shall mean a termination (i) by the Corporation without Cause, or (ii) by Executive Officer following Good Reason; provided, however, the term "Involuntary Termination" shall not include termination of Executive Officer's employment due to Executive Officer's death, Disability, or voluntary retirement.

(11) "Potential Change in Control" shall mean the earliest to occur of (i) the date on which the Corporation executes an agreement or letter of intent, where the consummation of the transaction described therein would result in the occurrence of a Change in Control, (ii) the date on which the Board of Directors approves a transaction or series of transactions, the consummation of which would result in a Change in Control, or (iii) the date on which a tender offer for the Corporation's voting stock is publicly announced, the completion of which would result in a Change in Control; provided, however, that if such Potential Change in Control terminates by its terms, such transaction shall no longer constitute a Potential Change in Control.

(12) "Potential Change in Control Date" shall mean the date on which a Potential Change in Control occurs.

(13) "Reference Salary" shall mean the greater of (i) the annual rate of Executive Officer's base salary from the Corporation or the employing subsidiary in effect immediately before the date of Executive Officer's Involuntary Termination, or (ii) the annual rate of Executive Officer's base salary from the Corporation or the employing subsidiary in effect immediately before the Change in Control Date.

(14) "Termination Date" shall be the date specified in the written notice of termination of Executive Officer's employment given by either party in accordance with Section 3(b) of this Policy.

(b) Notice of Termination. During the Covered Period, in the event that the Corporation (including an employing subsidiary) or Executive Officer terminates Executive Officer's employment with the Corporation or Employer, the party terminating employment shall give written notice of termination to the other party, specifying the Termination Date and the specific termination provision in this Section 3 that is relied upon, if any, and setting forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of Executive Officer's employment under the provision so indicated. The Termination Date shall be determined as follows: (i) if Executive Officer's employment is terminated for Disability, thirty (30) days after a Notice of Termination is given (provided that Executive Officer shall not have returned to the full-time performance of Executive Officer's duties during such 30-day period); (ii) if Executive Officer's employment is terminated by the Corporation in an Involuntary Termination, thirty days after the date the Notice of Termination is received by Executive Officer (provided that the Corporation may provide Officer with pay in lieu of notice, which shall be paid in a lump sum together with the payment described in Section 3(c)(1) below); and (iii) if Executive Officer's employment is terminated by the Corporation for Cause (as defined in this Section 3), the date specified in the Notice of Termination, provided, that the events or circumstances cited by the Board of Directors as constituting Cause are not cured by Executive Officer during any cure period that may be offered by the Board of Directors. The Date of Termination for a resignation of employment other than for Good Reason shall be the date set forth in the applicable notice, which shall be no earlier than ten (10) days after the date such notice is received by the Corporation, unless waived by the Corporation.

During the Covered Period, a notice of termination given by Executive Officer for Good Reason shall be given within 90 days after occurrence of the event on which Executive Officer bases his notice of termination and shall provide a Termination Date of thirty (30) days after the notice of termination is given to the Corporation (provided that the Corporation may provide Officer with pay in lieu of notice, which shall be paid in a lump sum together with the payment described in Section 3(c)(1) below).

(c) Corporation's Obligations. If Executive Officer separates from service due to an Involuntary Termination within the Covered Period, then the Corporation shall provide Executive Officer the following benefits:

(1) The Corporation shall pay to the Executive Officer a lump sum in cash within thirty (30) days after the Executive Officer's separation from service :

a. the sum of (1) any earned but unpaid base salary through the Termination Date at the rate in effect at the time of the notice of termination to the extent not theretofore paid; (2) the Executive Officer's pro-rated target bonus under the Short-Term Incentive Plan of the Corporation, an Affiliate, or a predecessor, for the fiscal year in which the Termination Date occurs (the " Target Bonus "); and (3) any accrued but unpaid vacation pay, in each case to the extent not theretofore paid;

b. the amount equal to the product of (1) two and (2) the sum of (x) the Reference Salary and (y) the Target Bonus; and

c. a lump sum cash payment equal to the estimated value of 18 months'of COBRA premiums for the Officer, based on the Officer's beneit levels at the time of termination (with such payment subject to taxation under applicable law), if any;

(2) Executive Officer shall be eligible to receive such career transition services as the Corporation's Senior Human Resources Officer shall determine is appropriate (if any), provided that payment of such services will only be made to the extent the Officer actually incurs an expense and then only to the extent incurred and paid within the time limit set forth in Treasury Regulation Section 1.409A-1(b)(9)(v)(E). Any such services, to the extent they are not exempt under Treasury Regulation Section 1.409A-1(b)(9)(v)(A) or (D), shall be structured to comply with the requirements of Treasuary Regulation Section 1.409A-3(i)(1)(iv) and, if applicable, shall be subject to the six-month delay described in Code Section 409A(a)(2)(B)(i).

(3) Remedies . The Executive Officer shall be entitled to recover damages for late or nonpayment of amounts which the Corporation is obligated to pay hereunder. The Executive Officer shall also be entitled to seek specific performance of the Corporation's obligations and any other applicable equitable or injunctive relief.

(d) Adjustment for Excise Taxes .

(1) "Best-Net Provision"

Subject to Section 3(d)(2) below, in the event that the payments and other benefits provided for in this Policy or otherwise payable to Executive Officer (i) constitute "parachute payments" within the meaning of Section 280G of the Internal Revenue Code of 1986, as amended (the "Code") and (ii) would be subject to the excise tax imposed by Section 4999 of the Code, then Executive Officer's payments and benefits under this Policy or otherwise payable to Executive Officer outside of this Policy shall be either delivered in full (without the Corporation paying any portion of such excise tax), or delivered as to 2.99 times of Executive's base amount (within the meaning of Section 280G of the Code) so as to result in no portion of such payments and benefits being subject to such excise tax, whichever of the foregoing amounts, taking into account the applicable federal, state and local income taxes and such excise tax, results in the receipt by Executive Officer on an after-tax basis of the greatest amount of payments and benefits, notwithstanding that all or some portion of such payments and benefits may subject to such excise tax. Unless the Corporation and Executive Officer otherwise agree in writing, any determination required under this Section 3(d)(1) shall be made in writing by Deloitte & Touche (the "Accounting Firm"), whose determination shall be conclusive and binding upon Executive Officer and the Corporation for all purposes. For purposes of making the calculations required by this Section 3(d)(1), the Accounting Firm may make reasonable assumptions and approximations concerning applicable taxes and may rely on reasonable, good faith interpretations concerning the application of Section 280G and 4999 of the Code. The Corporation and Executive Officer shall furnish to the Accounting Firm such information and documents as the Accounting Firm may reasonably request in order to make a determination under this Section 3(d)(1).

Any reduction in payments and/or benefits shall occur in the following order as reasonably determined by the Accounting Firm: (1) reduction of cash payments, (2) reduction of non-cash/non-equity-based payments or benefits, and (3) reduction of vesting acceleration of equity-based awards; provided, however, that any non-taxable payments or benefits shall be reduced last in accordance with the same categorical ordering rule. In the event items described in (1) or (2) are to be reduced, reduction shall occur in reverse chronological order such that the payment or benefit owed on the latest date following the occurrence of the event triggering the excise tax will be the first payment to be reduced (with reductions made pro-rata in the event payments are owed at the same time). In the event that acceleration of vesting of equity-based awards is to be reduced, such acceleration of vesting shall be cancelled in a manner such as to obtain the best economic benefit for the officer (with reductions made pro-rata if economically equivalent), as determined by the Accounting Firm.

4. Administration . The Policy shall be administered by the Senior Human Resources Officer of the Corporation (" Administrator "), who shall have the authority to interpret the Policy and make and revise such rules as may be reasonably necessary to administer the Policy. The Administrator shall have the duty and responsibility of maintaining records, making the requisite calculations, securing Officer releases, and disbursing payments hereunder. The Administrator's interpretations, determinations, rules, and calculations shall be final and binding on all persons and parties concerned.

5. No Mitigation . Payment of the amounts and benefits under Section2(a) and Section 3 (except as otherwise provided in Section 2(a)(5)) shall not be subject to offset, counterclaim, recoupment, defense or other claim, right or action which the Corporation or an Employer may have and shall not be subject to a requirement that Officer mitigate or attempt to mitigate damages resulting from Officer's termination of employment.

6. Amendment and Termination . The Corporation, acting through its Compensation Committee, reserves the right to amend or terminate the Policy at any time; provided, however, that any amendment which would reduce the aggregate level of benefits, or terminate the Policy, shall not become effective prior to the third anniversary of the Corporation giving notice to Officers of such amendment or termination.

7. Successors . The Corporation will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business or

assets of the Corporation expressly to assume and to agree to perform its obligations under this Policy in the same manner and to the same extent that the Corporation would be required to perform such obligations if no such succession had taken place; provided, however, that no such assumption shall relieve the Corporation of its obligations hereunder. As used herein, the “Corporation” shall mean the Corporation as hereinbefore defined and any successor to its business and/or assets as aforesaid which assumes and agrees to perform its obligations by operation or law or otherwise.

This Policy shall inure to the benefit of and be binding upon the Officer (and Officer’s personal representatives and heirs), Corporation and its successors and assigns, and any such successor or assignee shall be deemed substituted for the Corporation under the terms of this Policy for all purposes. As used herein, “successor” and “assignee” shall include any person, firm, corporation or other business entity which at any time, whether by purchase, merger or otherwise, directly or indirectly acquires the stock of the Corporation or to which the Corporation assigns this Policy by operation of law or otherwise. If Officer should die while any amount would still be payable to Officer hereunder if Officer had continued to live, all such amounts, unless otherwise provided herein, shall be paid in accordance with this Policy to Officer’s devisee, legatee or other designee, or if there is no such designee, to Officer’s estate.

8. Nonassignability of Benefits . The payments under this Policy or the right to receive future payments under this Policy 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 payments becomes bankrupt, the payments under the Policy of the person affected may be terminated by the Administrator who, in his or her 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 he or she deems appropriate.

9. Nonguarantee of Employment . Officers covered by the Policy are at-will employees, and nothing contained in this Policy shall be construed as a contract of employment between the Officer and the Corporation (or, where applicable, a subsidiary or affiliate of the Corporation), or as a right of the Officer to continued employment, or to remain as an Officer, or as a limitation on the right of the Corporation (or a subsidiary or affiliate of the Corporation) to discharge Officer at any time, with or without cause.

10. Benefits Unfunded and Unsecured . The payments under this Policy are unfunded, and the interest under this Policy of any Officer and such Officer’s right to receive payments under this Policy shall be an unsecured claim against the general assets of the Corporation.

11. Applicable Law . All questions pertaining to the construction, validity, and effect of the Policy 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.

12. Arbitration . With the exception of any request for specific performance, injunctive or other equitable relief, any dispute or controversy of any kind arising out of or related to this Policy, Officer’s employment with the Corporation (or with the employing subsidiary), the termination thereof or any claims for benefits shall be resolved exclusively by final and binding arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration

Association then in effect. Provided, however, that in making their determination, the arbitrators shall be limited to accepting the position of the Officer or the position of the Corporation, as the case may be. The only claims not covered by this Section 12 are claims for benefits under workers' compensation or unemployment insurance laws; such claims will be resolved under those laws. The place of arbitration shall be San Francisco, California. Parties may be represented by legal counsel at the arbitration but must bear their own fees for such representation. The prevailing party in any dispute or controversy covered by this Section 12, or with respect to any request for specific performance, injunctive or other equitable relief, shall be entitled to recover, in addition to any other available remedies specified in this Policy, all litigation expenses and costs, including any arbitrator or administrative or filing fees and reasonable attorneys' fees. Such expenses, costs and fees, if payable to Officer, shall be paid within 60 days after they are incurred. Both the Officer and the Corporation specifically waive any right to a jury trial on any dispute or controversy covered by this Section 12. Judgment may be entered on the arbitrators' award in any court of competent jurisdiction.

13. Reimbursements and In-Kind Benefits. Notwithstanding any other provision of this Policy, all reimbursements and in-kind benefits provided under this Policy shall be made or provided in accordance with the requirements of Code Section 409A, including, where applicable, the requirement that (i) the amount of expenses eligible for reimbursement and the provision of benefits in kind during a calendar year shall not affect the expenses eligible for reimbursement or the provision of in-kind benefits in any other calendar year; (ii) the reimbursement for an eligible expense will be made on or before the last day of the calendar year following the calendar year in which the expense is incurred (or by such earlier time set forth in this Policy); (iii) the right to reimbursement or right to in-kind benefit is not subject to liquidation or exchange for another benefit; and (iv) each reimbursement payment or provision of in-kind benefit shall be one of a series of separate payments (and each shall be construed as a separate identified payment) for purposes of Code Section 409A.

14. Separate Payments. Each payment and benefit under this Policy shall be a "separate payment" for purposes of Code Section 409A.

APPENDIX A

PARTICIPATING EMPLOYERS

PG&E Corporation
Pacific Gas and Electric Company
PG&E Corporation Support Services, Inc.

Exhibit 10.3

PG&E CORPORATION
2014 LONG-TERM INCENTIVE PLAN

RESTRICTED STOCK UNIT GRANT – NON-EMPLOYEE DIRECTORS

PG&E CORPORATION , a California corporation, hereby grants Restricted Stock Units to the Recipient named below. The Restricted Stock Units have been granted under the PG&E Corporation 2014 Long-Term Incentive Plan (the "LTIP"). Please note, however, that under the LTIP, this grant is subject to the terms of Section 7 of the PG&E Corporation 2006 Long-Term Incentive Plan as in effect immediately prior to the effectiveness of the LTIP (the "Prior LTIP"), and that references to the LTIP herein shall mean the Prior LTIP as required by the context. The terms and conditions of the Restricted Stock Units are set forth in this cover sheet and in the attached Restricted Stock Unit Agreement (the "Agreement").

Date of Grant: May 14, 2014

Name of Recipient:

Award ID Number:

Number of Restricted Stock Units:

By accepting this award, you agree to all of the terms and conditions described in the attached Agreement. You and PG&E Corporation agree to execute such further instruments and to take such further action as may reasonably be necessary to carry out the intent of the attached Agreement. You are also acknowledging receipt of this Grant, the attached Agreement, and a copy of the prospectus describing the LTIP and the May 14, 2014 Equity Awards for Non-Employee Directors under the LTIP, dated May 12, 2014.

Attachment

PG&E CORPORATION

2014 LONG-TERM INCENTIVE PLAN

RESTRICTED STOCK UNIT AGREEMENT FOR NON-EMPLOYEE DIRECTORS

The LTIP and Other Agreements

This Agreement constitutes the entire understanding between you and PG&E Corporation regarding the Restricted Stock Units, subject to the terms of the LTIP. Any prior agreements, commitments, or negotiations are superseded. In the event of any conflict or inconsistency between the provisions of this Agreement and the LTIP, the LTIP shall govern. Capitalized terms that are not defined in this Agreement are defined in the LTIP.

Grant of Restricted Stock Units

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

Vesting of Restricted Stock Units

In general, provided that you have not had a Separation from Service, your Restricted Stock Units will vest one year from the Date of Grant shown on the cover sheet to this Agreement (the "Normal Vesting Date"). As set forth elsewhere in this Agreement, the Restricted Stock Units may vest earlier upon the occurrence of certain events.

Dividends

Your Restricted Stock Unit account will be credited quarterly on each dividend payment date with additional Restricted Stock Units (including fractions computed to three decimal places), determined by dividing (1) the amount of cash dividends paid on the number of shares of PG&E Corporation common stock represented by the Restricted Stock Units previously credited to your Restricted Stock Unit account by (2) the Fair Market Value of a share of PG&E Corporation common stock on the dividend payment date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units covered by this Agreement.

Settlement

Vested Restricted Stock Units will be settled in an equal number of shares of PG&E Corporation common stock (a "Share"), rounded down to the nearest whole Share. PG&E Corporation shall issue Shares in settlement of vested Restricted Stock Units upon the earliest of (1) the Normal Vesting Date, (2) your Disability (as defined under Section 409A of the Code), (3) your death, (4) a Section 409A Change in Control, or (5) your Separation from Service following a Change in Control that does not qualify as a Section 409A Change in Control. However, if you previously made a timely, valid deferral election to receive Shares in settlement of vested Restricted Stock Units after the Normal Vesting Date (commencing in January of a year following the Normal Vesting Date), then settlement will be according to the terms of your election and the LTIP, unless settled earlier in a lump sum as set forth in the LTIP upon occurrence of any of the events listed in sections (2) – (5) above. Further, if pursuant to any such deferral election you begin receiving any annual installments, then upon the subsequent occurrence of any of the events listed in sections (2) – (5) above, any unpaid installments will be settled in a lump sum upon occurrence of the event, except to the extent that such acceleration would result in taxation under Section 409A of the Code.

Separation of Service

If you have a Separation from Service, whether voluntarily or involuntarily, before the Normal Vesting Date, all Restricted Stock Units subject to this Agreement that have not vested on account of your death, Disability (within the meaning of Section 409A of the Code) or a Change in Control will be automatically cancelled and forfeited; provided, however, that if you have a Separation from Service due to a pending Disability determination, forfeiture shall not occur until a finding that such Disability has not occurred.

Death/Disability

In the event of your Disability (as defined in Section 409A of the Code) or death , all Restricted Stock Units credited to your account under this Agreement will immediately become fully vested and be settled in accordance with the settlement provisions described above.

Change in Control

In the event of a Change in Control, all Restricted Stock Units credited to your account under this Agreement will immediately become fully vested and be settled in accordance with the settlement provisions described above.

Delay

PG&E Corporation shall delay the issuance of any Shares to the extent it is necessary to comply with Section 409A(a)(2)(B)(i) of the Code (relating to payments made to certain "key employees" of certain publicly traded companies); in such event, any Shares to which you would otherwise be entitled during the six (6) month period following the date of your Separation from Service (or shorter period ending on the date of your death following such Separation from Service) will instead be issued on the first business day following the expiration of the applicable delay period.

Withholding Taxes

PG&E Corporation generally will not be required to withhold taxes on taxable income recognized by you upon settlement of your Restricted Stock Units. However, any taxes that are required to be withheld will be payable by you in cash, by check, or through deductions from your compensation. Also, the Board may, in its discretion and subject to such restrictions as the Board may impose, permit you to satisfy such tax withholding obligations

	by electing to have PG&E Corporation withhold otherwise deliverable Shares having a fair market value equal to the amount that would be required to be withheld.
Voting and Other Rights	You shall not have voting rights with respect to the Restricted Stock Units until the date the underlying Shares are issued (as evidenced by appropriate entry on the books of PG&E Corporation or its duly authorized transfer agent).
Applicable Law	This Agreement will be interpreted and enforced under the laws of the State of California.

Exhibit 31.1

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

I, Anthony F. Earley, Jr., certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 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: July 31, 2014

ANTHONY F. EARLEY, JR.

Anthony F. Earley, Jr.
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 June 30, 2014 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: July 31, 2014

KENT M. HARVEY

Kent M. Harvey
Senior Vice President and Chief Financial Officer

Exhibit 31.2

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 June 30, 2014 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: July 31, 2014

CHRISTOPHER P. JOHNS
Christopher P. Johns
President

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

I, Dinyar B. Mistry, certify that:

1. I have reviewed this Quarterly Report on Form 10-Q for the quarter ended June 30, 2014 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: July 31, 2014

DINYAR B. MISTRY

Dinyar B. Mistry
Vice President, Chief Financial Officer and Controller

Exhibit 32.1

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

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended June 30 , 2014 ("Form 10-Q"), I, Anthony F. Earley, Jr., Chairman, Chief Executive Officer and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) 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.

ANTHONY F. EARLEY, JR.
ANTHONY F. EARLEY, JR.
Chairman, Chief Executive Officer and President

July 31, 2014

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

In connection with the accompanying Quarterly Report on Form 10-Q of PG&E Corporation for the quarter ended June 30 , 2014 (“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

July 31, 2014

Exhibit 32.2

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

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended June 30 , 2014 (“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. JONS

CHRISTOPHER P. JOHNS
President

July 31, 2014

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

In connection with the accompanying Quarterly Report on Form 10-Q of Pacific Gas and Electric Company for the quarter ended June 30 , 2014 (“Form 10-Q”), I, Dinyar B. Mistry, Vice President, Chief Financial Officer and Controller 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.

DINYAR B. MISTRY

DINYAR B. MISTRY
Vice President, Chief Financial Officer and Controller

July 31, 2014