PG&E Corp
Form 10-Q
October 28, 2014

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 September 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 October 20, 2014:	
PG&E Corporation:	475,088,027
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 SEPTEMBER 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
CCSF	City and County of San Francisco
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
EPA	Environmental Protection Agency
EPS	earnings per common share
FERC	Federal Energy Regulatory Commission
GAAP	U.S. 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
PD	proposed decision
PSEP	pipeline safety enhancement plan
ROE	return on equity
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 September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	2014	2013	2014	2013
Operating Revenues				
Electric	$4,012	$3,517	$10,246	$9,375
Natural gas	927	658	2,536	2,248
Total operating revenues	4,939	4,175	12,782	11,623
Operating Expenses				
Cost of electricity	1,782	1,645	4,341	3,817
Cost of natural gas	134	131	694	656
Operating and maintenance	1,287	1,585	3,914	4,179
Depreciation, amortization, and decommissioning	671	523	1,766	1,542
Total operating expenses	3,874	3,884	10,715	10,194
Operating Income	1,065	291	2,067	1,429
Interest income	2	2	7	6
Interest expense	(174)	(179)	(547)	(532)
Other income, net	36	26	98	78
Income Before Income Taxes	929	140	1,625	981
Income tax provision (benefit)	115	(24)	310	243
Net Income	814	164	1,315	738
Preferred stock dividend requirement of subsidiary	3	3	10	10
Income Available for Common Shareholders	$811	$161	$1,305	$728
Weighted Average Common Shares Outstanding, Basic	472	446	466	441
Weighted Average Common Shares Outstanding, Diluted	474	447	468	442
Net Earnings Per Common Share, Basic	$1.72	$0.36	$2.80	$1.65
Net Earnings Per Common Share, Diluted	$1.71	$0.36	$2.79	$1.65
Dividends Declared Per Common Share	$0.46	$0.46	$1.37	$1.37

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2014	2013	2014	2013
Net Income	$814	$164	$1,315	$738
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations (net of taxes of $0, $3, $0 and $10, at respective dates)	-	4	-	12
Net change in investments (net of taxes of $13, $2, $16, $13, at respective dates)	(18)	(3)	(24)	19
Total other comprehensive income (loss)	(18)	1	(24)	31
Comprehensive Income	796	165	1,291	769
Preferred stock dividend requirement of subsidiary	3	3	10	10
Comprehensive Income Attributable to Common Shareholders	$793	$162	$1,281	$759

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
(in millions)	September 30, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and cash equivalents	$139	$296
Restricted cash	299	301
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $68 and $80 at respective dates)	1,121	1,091
Accrued unbilled revenue	865	766
Regulatory balancing accounts	1,955	1,124
Other	328	312
Regulatory assets	391	448
Inventories:		
Gas stored underground and fuel oil	189	137
Materials and supplies	308	317
Income taxes receivable	177	574
Other	299	611
Total current assets	6,071	5,977
Property, Plant, and Equipment		
Electric	44,297	42,881
Gas	15,285	14,379
Construction work in progress	2,305	1,834
Other	2	2
Total property, plant, and equipment	61,889	59,096
Accumulated depreciation	(18,717)	(17,844)
Net property, plant, and equipment	43,172	41,252
Other Noncurrent Assets		
Regulatory assets	5,217	4,913
Nuclear decommissioning trusts	2,399	2,342
Income taxes receivable	93	85
Other	932	1,036
Total other noncurrent assets	8,641	8,376
TOTAL ASSETS	$57,884	$55,605

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	(Unaudited) Balance At September 30, 2014	December 31, 2013
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$426	$1,174
Long-term debt, classified as current	-	889
Accounts payable:		
Trade creditors	1,192	1,293
Regulatory balancing accounts	1,223	1,008
Other	425	471
Disputed claims and customer refunds	437	154
Interest payable	149	892
Other	1,874	1,612
Total current liabilities	5,726	7,493
Noncurrent Liabilities		
Long-term debt	14,555	12,717
Regulatory liabilities	6,133	5,660
Pension and other postretirement benefits	1,559	1,601
Asset retirement obligations	3,570	3,539
Deferred income taxes	8,032	7,823
Other	2,278	2,178
Total noncurrent liabilities	36,127	33,518
Commitments and Contingencies (Note 10)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares; 474,534,357 and 456,670,424 shares outstanding at respective dates	10,350	9,550
Reinvested earnings	5,403	4,742
Accumulated other comprehensive income	26	50
Total shareholders' equity	15,779	14,342
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	16,031	14,594
TOTAL LIABILITIES AND EQUITY	$57,884	$55,605

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Nine Months Ended September 30,	
(in millions)	2014	2013
Cash Flows from Operating Activities		
Net income	$ 1,315	$ 738
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,766	1,542
Allowance for equity funds used during construction	(72)	(78)
Deferred income taxes and tax credits, net	209	527
PSEP disallowed capital expenditures	-	196
Other	258	274
Effect of changes in operating assets and liabilities:		
Accounts receivable	(177)	(160)
Inventories	(43)	(56)
Accounts payable	(57)	84
Income taxes receivable/payable	397	(133)
Other current assets and liabilities	358	(269)
Regulatory assets, liabilities, and balancing accounts, net	(994)	12
Other noncurrent assets and liabilities	(3)	156
Net cash provided by operating activities	2,957	2,833
Cash Flows from Investing Activities		
Capital expenditures	(3,564)	(3,881)
Decrease in restricted cash	2	29
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,059	1,152
Purchases of nuclear decommissioning trust investments	(1,065)	(1,150)
Other	107	37
Net cash used in investing activities	(3,461)	(3,813)
Cash Flows from Financing Activities		
Borrowings under revolving credit facilities	-	140
Repayments under revolving credit facilities	(260)	-
Net issuances (repayments) of commercial paper, net of discount of $1 at respective dates	(789)	322
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 $6 and $9 at respective dates	1,819	741
Repayments of long-term debt	(889)	(461)
Common stock issued	743	724
Common stock dividends paid	(617)	(583)
Other	40	(23)
Net cash provided by financing activities	347	860
Net change in cash and cash equivalents	(157)	(120)
Cash and cash equivalents at January 1	296	401

Cash and cash equivalents at September 30	$139	$281
Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(516)	$(499)
Income taxes, net	409	(65)
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	$216	$204
Capital expenditures financed through accounts payable	232	277
Noncash common stock issuances	16	17
Terminated capital leases	71	-

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2014	2013	2014	2013
Operating Revenues				
Electric	$4,012	$3,517	$10,244	$9,372
Natural gas	927	657	2,536	2,248
Total operating revenues	4,939	4,174	12,780	11,620
Operating Expenses				
Cost of electricity	1,782	1,645	4,341	3,817
Cost of natural gas	134	131	694	656
Operating and maintenance	1,293	1,583	3,911	4,175
Depreciation, amortization, and decommissioning	671	523	1,765	1,542
Total operating expenses	3,880	3,882	10,711	10,190
Operating Income	1,059	292	2,069	1,430
Interest income	1	2	6	6
Interest expense	(171)	(172)	(535)	(513)
Other income, net	19	20	56	66
Income Before Income Taxes	908	142	1,596	989
Income tax provision (benefit)	115	(20)	325	261
Net Income	793	162	1,271	728
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	$790	$159	$1,261	$718

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited)			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2014	2013	2014	2013
Net Income	$793	$162	$1,271	$728
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations (net of taxes of $0, $3, $0 and $9, at respective dates)	-	4	-	13
Total other comprehensive income	-	4	-	13
Comprehensive Income	$793	$166	$1,271	$741

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
(in millions)	September 30, 2014	December 31, 2013
ASSETS		
Current Assets		
Cash and cash equivalents	$85	$65
Restricted cash	299	301
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $68 and $80 at respective dates)	1,121	1,091
Accrued unbilled revenue	865	766
Regulatory balancing accounts	1,955	1,124
Other	326	313
Regulatory assets	391	448
Inventories:		
Gas stored underground and fuel oil	189	137
Materials and supplies	308	317
Income taxes receivable	156	563
Other	260	523
Total current assets	5,955	5,648
Property, Plant, and Equipment		
Electric	44,297	42,881
Gas	15,285	14,379
Construction work in progress	2,305	1,834
Total property, plant, and equipment	61,887	59,094
Accumulated depreciation	(18,715)	(17,843)
Net property, plant, and equipment	43,172	41,251
Other Noncurrent Assets		
Regulatory assets	5,217	4,913
Nuclear decommissioning trusts	2,399	2,342
Income taxes receivable	88	81
Other	834	814
Total other noncurrent assets	8,538	8,150
TOTAL ASSETS	$57,665	$55,049

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	(Unaudited) Balance At September 30, 2014	December 31, 2013
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$426	$914
Long-term debt, classified as current	-	539
Accounts payable:		
Trade creditors	1,192	1,293
Regulatory balancing accounts	1,223	1,008
Other	440	432
Disputed claims and customer refunds	437	154
Interest payable	148	887
Other	1,686	1,382
Total current liabilities	5,552	6,609
Noncurrent Liabilities		
Long-term debt	14,205	12,717
Regulatory liabilities	6,133	5,660
Pension and other postretirement benefits	1,485	1,530
Asset retirement obligations	3,570	3,539
Deferred income taxes	8,215	8,042
Other	2,240	2,111
Total noncurrent liabilities	35,848	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	6,521	5,821
Reinvested earnings	8,151	7,427
Accumulated other comprehensive income	13	13
Total shareholders' equity	16,265	14,841
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$57,665	$55,049

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Nine Months Ended September 30,	
(in millions)	2014	2013
Cash Flows from Operating Activities		
Net income	$1,271	$728
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,765	1,542
Allowance for equity funds used during construction	(72)	(78)
Deferred income taxes and tax credits, net	173	545
PSEP disallowed capital expenditures	-	196
Other	212	231
Effect of changes in operating assets and liabilities:		
Accounts receivable	(174)	(162)
Inventories	(43)	(56)
Accounts payable	(3)	125
Income taxes receivable/payable	407	(154)
Other current assets and liabilities	366	(250)
Regulatory assets, liabilities, and balancing accounts, net	(994)	12
Other noncurrent assets and liabilities	6	147
Net cash provided by operating activities	2,914	2,826
Cash Flows from Investing Activities		
Capital expenditures	(3,564)	(3,881)
Decrease in restricted cash	2	29
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,059	1,152
Purchases of nuclear decommissioning trust investments	(1,065)	(1,150)
Other	22	14
Net cash used in investing activities	(3,546)	(3,836)
Cash Flows from Financing Activities		
Net issuances (repayments) of commercial paper, net of discount of $1 at respective dates	(789)	322
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 $3 and $9 at respective dates	1,472	741
Repayments of long-term debt	(539)	(461)
Preferred stock dividends paid	(10)	(10)
Common stock dividends paid	(537)	(537)
Equity contribution	705	835
Other	50	(14)
Net cash provided by financing activities	652	876
Net change in cash and cash equivalents	20	(134)
Cash and cash equivalents at January 1	65	194
Cash and cash equivalents at September 30	$85	$60

Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(500)	$(487)
Income taxes, net	408	(86)
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$232	$277
Terminated capital leases	71	-

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 September 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 September 30, 2014, it did not consolidate any of them.

PG&E Corporation affiliates previously entered into four tax equity agreements to fund residential and commercial retail solar energy installations with four separate privately held funds that were considered VIEs. On July 2, 2014, PG&E Corporation disposed of its interest in the tax equity agreements and 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 nine months ended September 30, 2014 and 2013 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended September 30,			
(in millions)	2014	2013	2014	2013
Service cost for benefits earned	$92	$121	$12	$14
Interest cost	175	158	19	19
Expected return on plan assets	(202)	(162)	(25)	(20)
Amortization of prior service cost	5	5	6	6
Amortization of net actuarial loss	1	28	1	1
Net periodic benefit cost	71	150	13	20
Transfer from (to) regulatory account (1)	13	(66)	-	-
Total	$84	$84	$13	$20

(1) The Utility recorded these amounts to a regulatory account since they are probable of recovery from, or refund to, customers in future rates.

	Pension Benefits		Other Benefits	
	Nine Months Ended September 30,			
(in millions)	2014	2013	2014	2013
Service cost for benefits earned	$287	$351	$34	$40
Interest cost	521	470	57	56
Expected return on plan assets	(605)	(487)	(77)	(60)
Amortization of prior service cost	15	15	17	17
Amortization of net actuarial loss	2	83	2	4
Net periodic benefit cost	220	432	33	57
Transfer from (to) regulatory account (1)	31	(179)	-	-
Total	$251	$253	$33	$57

(1) The Utility recorded these amounts to a regulatory account since they are probable of recovery from, or refund to, 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 September 30, 2014			
Beginning balance	$(7)	$15	$36	$44
Other comprehensive income before reclassifications:				
Loss on investments (net of taxes of $0, $0, and $3, respectively)	-	-	(4)	(4)
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (net of taxes of $2, $3, and $0, respectively) (1)	3	3	-	6
Transfer to regulatory account (net of taxes of $3, $4, and $0, respectively) (1)	(3)	(3)	-	(6)
Realized gain on investments (net of taxes of $0, $0, and $10, respectively)	-	-	(14)	(14)
Net current period other comprehensive loss	-	-	(18)	(18)
Ending balance	$(7)	$15	$18	$26

(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 September 30, 2013			
Beginning balance	$(28)	$(69)	$26	$(71)
Other comprehensive income before reclassifications:				
Loss on investments (net of taxes of $0, $0, and $2, respectively)	-	-	(3)	(3)
Amounts reclassified from other comprehensive income: (1)				
Amortization of prior service cost (net of taxes of $2, $3, and $0, respectively)	3	3	-	6
Amortization of net actuarial loss (net of taxes of $11, $0, and $0, respectively)	17	1	-	18
Transfer to regulatory account (net of taxes of $13, $0, and $0, respectively)	(20)	-	-	(20)
Net current period other comprehensive income (loss)	-	4	(3)	1
Ending balance	$(28)	$(65)	$23	$(70)

(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
	Nine Months Ended September 30, 2014			
Beginning balance	$(7)	$15	$42	$50
Other comprehensive income before reclassifications:				
Gain on investments (net of taxes of $0, $0, and $4, respectively)	-	-	6	6
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost (net of taxes of $6, $7, and $0, respectively) (1)	9	10	-	19
Amortization of net actuarial loss (net of taxes of $1, $1, and $0, respectively) (1)	1	1	-	2
Transfer to regulatory account (net of taxes of $7, $8, and $0, respectively) (1)	(10)	(11)	-	(21)
Realized gain on investments (net of taxes of $0, $0, and $20, respectively)	-	-	(30)	(30)
Net current period other comprehensive loss	-	-	(24)	(24)
Ending balance	$(7)	$15	$18	$26

(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
	Nine Months Ended September 30, 2013			
Beginning balance	$(28)	$(77)	$4	$(101)
Other comprehensive income before reclassifications:				
Gain on investments (net of taxes of $0, $0, and $13, respectively)	-	-	19	19
Amounts reclassified from other comprehensive income: (1)				
Amortization of prior service cost (net of taxes of $6, $8, and $0, respectively)	9	9	-	18
Amortization of net actuarial loss (net of taxes of $34, $1, and $0, respectively)	49	3	-	52
Transfer to regulatory account (net of taxes of $39, $0, and $0, respectively)	(58)	-	-	(58)
Net current period other comprehensive income	-	12	19	31
Ending balance	$(28)	$(65)	$23	$(70)

(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)	September 30, 2014	December 31, 2013
Pension benefits	$1,397	$1,444
Deferred income taxes	2,269	1,835
Utility retained generation	468	503
Environmental compliance costs	714	628
Price risk management	83	106
Electromechanical meters	87	135
Unamortized loss, net of gain, on reacquired debt	118	135
Other	81	127
Total long-term regulatory assets	$5,217	$4,913

Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

	Balance at	
(in millions)	September 30, 2014	December 31, 2013
Cost of removal obligations	$4,144	$3,844
Recoveries in excess of asset retirement obligations	687	748
Public purpose programs	705	587
Other	597	481
Total long-term regulatory liabilities	$6,133	$5,660

Regulatory Balancing Accounts

The Utility's recovery of revenue requirements and costs is generally decoupled from the volume of sales. The Utility tracks (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 expects to collect or refund over a period exceeding 12 months are recorded as 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.

The balancing accounts reflect the impacts of the final decision in the Utility's 2014 GRC that was issued by the CPUC on August 14, 2014.

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

	Receivable Balance at	
(in millions)	September 30, 2014	December 31, 2013
Electric distribution	$173	$102
Utility generation	162	57
Gas distribution	549	70
Energy procurement	633	410
Public purpose programs	106	56
Other	332	429
Total regulatory balancing accounts receivable	$1,955	$1,124

	Payable Balance at	
(in millions)	September 30, 2014	December 31, 2013
Energy procurement	$286	$298
Public purpose programs	157	171
Other (1)	780	539
Total regulatory balancing accounts payable	$1,223	$1,008

(1) At September 30, 2014, Other regulatory balancing accounts payable mostly includes energy supplier settlements. (See Note 9 Resolution of Remaining Chapter 11 Disputed Claims for additional details.)

NOTE 4: DEBT

Senior Notes

The following senior notes were issued during 2014:

(in millions)	Issuance Date	Principal Amount		Maturity Date
PG&E Corporation				
2.40% Senior Notes	February 2014	$350	(1)	March 1, 2019
Utility				
Floating Rate Senior Notes	May 2014	300	(2)	May 11, 2015
3.75% Senior Notes	February 2014	450	(3)	February 15, 2024
3.40% Senior Notes	August 2014	350	(4)	August 15, 2024
4.75% Senior Notes	February 2014	450	(3)	February 15, 2044
4.75% Senior Notes	August 2014	225	(4)	February 15, 2044
Total senior note issuances		$2,125		

(1) The proceeds were used to repay the 5.75% Senior Notes, in the principal outstanding amount of $350 million.
(2) The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.
(3) 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.
(4) The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper, and to fund capital expenditures.

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 September 30, 2014:

(in millions)	Termination Date	Facility Limit		Letters of Credit Outstanding	Commercial Paper	Facility Availability
PG&E Corporation	April 2019	$300	(1)	$ -	$ -	$ 300
Utility	April 2019	3,000	(2)	84	126	2,790
Total revolving credit facilities		$3,300		$ 84	$ 126	$ 3,090

(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 September 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 0.03%. At September 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 0.03%.

NOTE 5: EQUITY

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

(in millions)	PG&E Corporation Total Equity	Utility Total Shareholders' Equity
Balance at December 31, 2013	$ 14,594	$ 14,841
Comprehensive income	1,291	1,271
Equity contributions	-	705
Common stock issued	759	-
Share-based compensation	41	(5)
Common stock dividends declared	(644)	(537)
Preferred stock dividend requirement	-	(10)
Preferred stock dividend requirement of subsidiary	(10)	-
Balance at September 30, 2014	$ 16,031	$ 16,265

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. During the three and nine months ended September 30, 2014, PG&E Corporation sold 2 million and 11 million shares, respectively, under the February 2014 equity distribution agreement for cash proceeds of $67 million and $496 million, respectively, exhausting the remaining capacity under this agreement. These amounts are net of commissions paid of $1 million and $4 million, respectively.

In addition, PG&E Corporation issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the nine months ended September 30, 2014, 7 million shares were issued for cash proceeds of $247 million under these plans.

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 September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	2014	2013	2014	2013
Income available for common shareholders	$811	$161	$1,305	$728
Weighted average common shares outstanding, basic	472	446	466	441
Add incremental shares from assumed conversions:				
Employee share-based compensation	2	1	2	1
Weighted average common share outstanding, diluted	474	447	468	442
Total earnings per common share, diluted	$1.71	$0.36	$2.79	$1.65

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 September 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	218,107,731	70,621,174	3,530,000	-
	Options	116,213,741	62,844,400	-	-
Electricity (Megawatt-hours)	Forwards and Swaps	1,364,184	1,956,498	1,574,588	969,478
	Congestion Revenue Rights	55,886,532	87,533,830	41,126,312	22,755,431

(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 September 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	$51	$(6)	$15	$60
Other noncurrent assets – other	81	(4)	-	77
Current liabilities – other	(57)	6	6	(45)
Noncurrent liabilities – other	(87)	4	-	(83)
Net commodity risk	$(12)	$-	$21	$9

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 September 30,		Nine Months Ended September 30,	
(in millions)	2014	2013	2014	2013
Unrealized gain (loss) - regulatory assets and liabilities (1)	$(6)	$40	$79	$115
Realized loss - cost of electricity (2)	(22)	(57)	(48)	(136)
Realized loss - cost of natural gas (2)	(4)	(2)	(7)	(14)
Net commodity risk	$(32)	$(19)	$24	$(35)

(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 September 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)	September 30, 2014	December 31, 2013
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$(22)	$(79)
Related derivatives in an asset position	1	4
Collateral posting in the normal course of business related to these derivatives	8	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 September 30, 2014				
(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Money market investments	$53	$-	$-	$-	$53
Nuclear decommissioning trusts					
Money market investments	16	-	-	-	16
U.S. equity securities	1,118	12	-	-	1,130
Non-U.S. equity securities	432	1	-	-	433
U.S. government and agency securities	745	164	-	-	909
Municipal securities	-	54	-	-	54
Other fixed-income securities	-	163	-	-	163
Total nuclear decommissioning trusts (2)	2,311	394	-	-	2,705
Price risk management instruments (Note 7)					
Electricity	1	29	95	5	130
Gas	3	4	-	-	7
Total price risk management instruments	4	33	95	5	137
Rabbi trusts					
Fixed-income securities	-	41	-	-	41
Life insurance contracts	-	71	-	-	71
Total rabbi trusts	-	112	-	-	112
Long-term disability trust					
Money market investments	4	-	-	-	4
U.S. equity securities	-	9	-	-	9
Non-U.S. equity securities	-	12	-	-	12
Fixed-income securities	-	107	-	-	107
Total long-term disability trust	4	128	-	-	132
Other investments	36	-	-	-	36
Total assets	$2,408	$667	$95	$5	$3,175
Liabilities:					

Price risk management instruments (Note 7)					
Electricity	$9	$17	$115	$(16)	$125
Gas	3	-	-	-	3
Total liabilities	$12	$17	$115	$(16)	$128

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $306 million, primarily related to deferred taxes on appreciation of investment value.

	Fair Value Measurements At December 31, 2013				
(in millions)	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. 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 nine months ended September 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.

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 September 30, 2014				
Fair Value Measurement	Assets	Liabilities	Valuation Technique	Unobservable Input	Range (1)
Congestion revenue rights	$ 95	$ 28	Market approach	CRR auction prices	$ (19.16) - 12.04
Power purchase agreements	$ -	$ 87	Discounted cash flow	Forward prices	$ 22.54 - 63.45

(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 nine months ended September 30, 2014 and 2013:

(in millions)	Price Risk Management Instruments 2014	Price Risk Management Instruments 2013
Liability balance as of July 1	$(11)	$(76)
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(9)	(6)
Liability balance as of September 30	$(20)	$(82)

(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.

(in millions)	Price Risk Management Instruments 2014	Price Risk Management Instruments 2013
Liability balance as of January 1	$(30)	$(79)
Realized and unrealized gains (losses):		
Included in regulatory assets and liabilities or balancing accounts (1)	10	(3)
Liability balance as of September 30	$(20)	$(82)

(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, floating rate senior notes, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at September 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 September 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 September 30, 2014		At December 31, 2013	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
PG&E Corporation	$349	$351	$350	$354
Utility	13,283	14,992	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 September 30, 2014				
Nuclear decommissioning trusts				
Money market investments	$16	$-	$-	$16
Equity securities				
U.S.	269	863	(2)	1,130
Non-U.S.	256	183	(6)	433
Debt securities				
U.S. government and agency securities	855	57	(3)	909
Municipal securities	50	4	-	54
Other fixed-income securities	163	1	(1)	163
Total nuclear decommissioning trusts (1)	1,609	1,108	(12)	2,705
Other investments	5	31	-	36
Total	$1,614	$1,139	$(12)	$2,741
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 $306 million and $313 million at September 30, 2014 and December 31, 2013, respectively, primarily related to deferred taxes on appreciation of investment value.

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

(in millions)	As of September 30, 2014
Less than 1 year	$27
1–5 years	483
5–10 years	257
More than 10 years	359
Total maturities of debt securities	$1,126

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
(in millions)				
Proceeds from sales and maturities of nuclear decommissioning trust investments	$182	$357	$1,059	$1,152
Gross realized gains on securities held as available-for-sale	30	7	114	44
Gross realized losses on securities held as available-for-sale	-	(4)	(3)	(10)

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 has 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.

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.

In August 2014, the Utility received a letter from the California Power Exchange clarifying its ultimate intent to offset the Utility's remaining disputed claims principal and interest balances through net settlement. Accordingly, the Utility has presented $437 million of net Disputed claims and customer refunds on the Condensed Consolidated Balance Sheets at September 30, 2014, which includes both principal and interest. At December 31, 2013, the Condensed Consolidated Balance Sheets reflected $154 million of Disputed claims and customer refunds and $710 million of Interest payable.

At September 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.

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.

Enforcement and Litigation Matters

Pending CPUC Investigations

On September 2, 2014, the assigned CPUC ALJs issued their presiding officer decisions in the three investigative enforcement proceedings pending against the Utility. As previously disclosed in the 2013 Annual Report, these investigations relate to the Utility's natural gas transmission operations and practices and the San Bruno accident that occurred on September 9, 2010. The ALJs determined that the Utility committed approximately 3,700 violations of law, rules and regulations. The ALJs jointly issued a decision (the "Penalty Decision") calling for total penalties of $1.4 billion on the Utility to address all violations, allocated as follows: (1) $950 million fine to be paid to the State General Fund, (2) $400 million refund to ratepayers of previously authorized revenues, and (3) remedial measures that the ALJs estimate will cost the Utility at least $50 million. The ALJs' decisions are not the final decisions of the CPUC. As described below, the Utility and other parties have appealed these decisions. In addition, three CPUC Commissioners have requested that the CPUC review the decisions. It is possible that one or more Commissioners will issue an alternate penalty decision for consideration by the CPUC. (Two of the five CPUC Commissioners have recused themselves from voting on the final outcome of the investigations.)

On October 2, 2014, the Utility and other parties, including TURN, ORA, and CCSF filed appeals with the CPUC of the presiding officer decisions. In its appeals, the Utility argues that the penalties imposed and the findings and conclusions on which they are based do not meet applicable legal standards, are based on the misapplication of California law and regulations, and are unconstitutional. The Utility has asked the CPUC to order the Utility to pay a significantly reduced penalty that is reasonable and proportionate in light of the nature of the violations and that takes into account the substantial unrecovered amounts the Utility has already spent and forecasts that it will spend on gas system safety. The Utility requests that it be allowed 180 days to raise the funds it may be ordered to pay to the State General Fund rather than the 40 days specified in the Penalty Decision. The Utility also argues that the entire penalty should go toward funding investments in the Utility's gas transmission system.

TURN, ORA, and CCSF jointly filed an appeal urging the CPUC to disallow the Utility's recovery of remaining PSEP costs of $877 million and to require the Utility to pay $473 million to the State General Fund. These parties also argue that the record in the investigative proceedings would support an even larger penalty than stated in the Penalty Decision. The City of San Bruno appealed the rejection of its proposals for the appointment of an independent monitor to oversee the Utility's natural gas operations and for the establishment of a pipeline safety trust. On October 27, 2014, the parties filed responses to the various appeals.

It is uncertain when the outcome of these investigations will be determined. There continues to be significant uncertainty regarding the ultimate form and amount of penalty while the various appeals and requests for review of the presiding officer's decisions are unresolved. The impact on PG&E Corporation's and the Utility's consolidated financial statements will vary depending on the forms and amounts of penalties that are ultimately adopted by the CPUC. Fines payable to the State General Fund or refunds of revenues previously authorized would be charged to net income when it is probable that such penalties will be imposed and the amounts can be reasonably estimated. A disallowance of previously authorized and incurred capital costs would be charged to net income when the disallowance is probable and the amount can be reasonably estimated. (See "Pipeline Safety Enhancement Plan" below.) Penalties in the form of future shareholder-funded pipeline work would be charged to net income in the period during which the actual costs are incurred.

At September 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. Although the CPUC may impose total penalties on the Utility of $1.4 billion or higher, consistent with the Penalty Decision, the Utility is unable to make a better estimate of probable fines or make a reasonable estimate of probable disallowances or other refunds due to the variety of potential outcomes that could result from the various appeals and Commissioners' requests for review. PG&E Corporation's and the Utility's estimates and the assumptions on which they are based are subject to change as developments in the appeal process occur or if alternate penalty decisions are issued for CPUC consideration. Future changes in estimates or assumptions could have a material impact on future financial condition, results of operations, and cash flows. PG&E Corporation and the Utility believe the final outcome of the investigations will have a material impact on their financial condition, results of operations, and cash flows.

Federal 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 illegally obstructed the NTSB's investigation of the San Bruno accident. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also seeks an 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." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. 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. A status conference is scheduled to be held in court on November 3, 2014. 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 considered to be probable.

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 final penalties.

Improper CPUC Communications

In September and October 2014, the Utility notified the CPUC that the Utility believes certain communications between the Utility and CPUC personnel violated the CPUC's rules regarding ex parte communications. Ex parte communications include any communications concerning substantive issues in a formal proceeding before the CPUC, between a decision maker and an interested person, that does not occur in an established public forum or on the record. Some of these communications relate to the 2015 GT&S rate case, in which the Utility has requested a $555 million increase in natural gas transmission and storage revenues effective January 1, 2015. On October 16, 2014, a CPUC ALJ issued a ruling, effective immediately, that bans the Utility from engaging in any oral or written ex parte communications, as well as procedural communications, with Commissioners or their advisors (other than during all-party meetings) regarding the GT&S rate case or any other rate-setting or adjudicatory proceeding before the CPUC, for a one-year period or until the resolution of the GT&S rate case, whichever is later. (The ALJ also issued a PD requesting the CPUC to affirm the ruling.) In addition, the CPUC Commissioner who is assigned to the GT&S rate case issued an alternate PD on October 16, 2014, that, among other provisions, would impose a $1.05 million fine and adopt a ratemaking disallowance of no more than half of the revenue increase, as authorized by a final CPUC decision in the 2015 GT&S rate case, that would have been amortized (collected from ratepayers) over the period between the original planned timing of a final decision (March 2015) and the modified schedule for a final decision. Comments by parties on the PD and alternate PD are due on November 5, 2014.

Neither the PD nor the alternate PD address the additional ex parte communications that the Utility identified and reported to the CPUC on October 6, 2014. The Utility believes it is probable that CPUC enforcement actions will be taken in connection with these additional ex parte communications.

In addition, the U.S. Attorney's Office in San Francisco and the California Attorney General's office have begun investigations in connection with these communications. The Utility is cooperating with the federal and state investigators. It is uncertain whether any charges will be brought against the Utility.

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. As of September 30, 2014, the Utility has submitted 70 self-reports (plus several follow-up reports) that the SED has not yet addressed. Among other reports, 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 has notified the SED that employees who are performing this work have undergone the 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.

Carmel Incident

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 U.S. Attorney's Office is investigating the Carmel incident and the Utility is cooperating with federal investigators. The CPUC and local Carmel officials are also continuing to investigate the incident. The City of Carmel has requested the CPUC to issue an order instituting a formal investigation into whether the Utility violated applicable laws and regulations. The Utility believes it is probable that enforcement actions will be taken in connection with this matter.

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.

Kern Power Plant

On August 28, 2014, the CPUC issued an order instituting a formal investigation into a contract worker fatality that occurred in June 2012 during the dismantling of an unused fuel tank at the Utility's retired Kern power plant in Bakersfield, California. The SED conducted an investigation of the incident and has alleged that the Utility failed to adequately evaluate safety in contract bid proposals; did not provide adequate contractor project safety review and oversight; and neglected to evaluate safer alternatives. The SED also alleged that the Utility failed to conduct a prompt and thorough incident root cause analysis, as requested by the SED, in order to assist in identifying and implementing effective corrective actions to improve safety and reduce the likelihood of future incidents. The CPUC also noted that the SED's investigation into a 2013 incident at the Kern power plant is ongoing. In that incident, a bystander who was observing the demolition of the plant was severely injured by debris from the explosion.

The Utility and the SED are currently engaged in negotiations to reach a stipulated outcome of this proceeding. The CPUC ALJ has deferred adoption of a procedural schedule to enable the parties to continue to engage in negotiations. Any settlement agreement that may be reached would be submitted to the CPUC for its consideration. The Utility and the SED are scheduled to file a status report with the ALJ on November 3, 2014. It is reasonably possible that fines will be imposed on the Utility in connection with this matter. The CPUC also could order the Utility to comply with additional remedial measures, such as requiring the Utility to correct identified deficiencies and to further improve the safety of its operations.

Pipeline Safety Enhancement Plan

On October 16, 2014, a PD was issued that would approve the settlement agreement (submitted in July 2014) among the Utility, the CPUC's ORA and TURN, to resolve the Utility's PSEP Update application (submitted in October 2013). The total PSEP-related revenue requirements (2012-2014) proposed in the settlement agreement reflect a proposed $23 million reduction to expense funding, as compared to the Utility's request. The Utility has recorded a charge against operating revenue to reflect the cumulative impact of this reduction. There would be no 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 September 30, 2014, approximately $540 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 in its final decision. Comments on the PD are due November 5, 2014. The CPUC will vote on the PD, at the earliest, on November 20, 2014. The Utility's ability to recover PSEP-related costs also could be affected by final decisions 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 alleged 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 alleged that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs sought restitution and disgorgement, as well as compensatory and punitive damages. 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. In October 2014, the Court of Appeals affirmed the court's ruling to dismiss the complaint. PG&E Corporation and the Utility believe it is remote that any material losses will be incurred in connection with this complaint.

Other Legal and Regulatory Contingencies

Accruals for other legal and regulatory contingencies (excluding amounts related to the enforcement and litigation matters described above) totaled $35 million at September 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)	September 30, 2014	December 31, 2013
Topock natural gas compressor station (1)	$294	$264
Hinkley natural gas compressor station (1)	163	190
Former manufactured gas plant sites owned by the Utility or third parties	262	184
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites	156	160
Fossil fuel-fired generation facilities and sites	101	102
Total environmental remediation liability	$976	$900

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

At September 30, 2014 the Utility expected to recover $678 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 the final cleanup and abatement order in mid-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 Utility has discontinued its whole house water replacement program as a result of the State of California's new drinking water standard for hexavalent chromium that became effective on July 1, 2014.

The Utility's environmental remediation liability at September 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. In September 2014, the Utility submitted its 90% remedial design plan to regulatory authorities and expects to submits its final remedial design plan in 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 September 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 $1.8 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 closing agreement settling the federal audit of the 2008 and 2010 tax years. As a result, PG&E Corporation received a federal cash refund of $411 million in August 2014.

The 2014 GRC decision authorized flow-through ratemaking for temporary differences attributable to repair costs and certain other property-related costs for federal tax purposes. PG&E Corporation's and the Utility's financial results reflect a reduction in income tax expense associated with these temporary differences consistent with this ratemaking method. In addition, recent guidance from the IRS allows the Utility to deduct more repair costs than previously forecasted in the GRC. For the three months ended September 30, 2014, the Utility recognized a reduction in income tax expense consistent with GRC and IRS guidance for $175 million for the application of flow-through ratemaking effective as of January 1, 2014.

The following table reconciles the income tax expense at the federal statutory rate to the income tax provision:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014		2013		2014		2013	
Federal statutory income tax rate	35.0	%	35.0	%	35.0	%	35.0	%
Increase (decrease) in income tax rate resulting from:								
State income tax (net of federal benefit) (1)	2.9		(25.0	)	1.9		(2.1	)
Effect of regulatory treatment of fixed asset differences (2)	(19.9	)	(10.1	)	(13.0	)	(2.9	)
Tax credits	(0.4	)	(1.6	)	(0.5	)	(0.4	)
Benefit of loss carryback	0.2		(1.9	)	(0.2	)	(0.2	)
Other, net (3)	(5.2	)	(10.4	)	(2.8	)	(3.0	)
Effective tax rate	12.6	%	(14.0	) %	20.4	%	26.4	%

(1) Includes the effect of state flow-through ratemaking treatment. Additionally, during the three months ended September 30, 2013, the Utility recorded an adjustment to state income taxes in connection with an IRS settlement.
(2) Represents effect of federal flow-through ratemaking treatment including those deductions related to repairs and certain other property-related costs discussed above.
(3) Primarily relates to research and development tax credits and other timing differences.

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

The IRS is currently reviewing several matters in the 2011, 2012, and 2013 tax returns. The most significant relates to a 2011 accounting method change to adopt guidance issued by the IRS in determining which repair costs are deductible for the electric distribution and transmission businesses. The IRS is expected to issue guidance by the end of 2014 that determines which repair costs are deductible for the natural gas transmission and distribution businesses. PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months depending on the IRS guidance that is issued and the resolution of the audits related to the 2011, 2012, and 2013 tax returns. As of September 30, 2014, it is reasonably possible that unrecognized tax benefits will decrease by approximately $380 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 nine months ended September 30, 2014.

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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 nuclear generating facility located at Humboldt Bay. 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. NEIL provides coverage for nuclear and non-nuclear property damages of up to $131 million for the retired Humboldt Bay Facility. 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. 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 the retired Humboldt Bay facility and has a $500 million indemnification from the NRC for public liability claims 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 nine months ended September 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 $2.2 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

PG&E Corporation's financial results for the three and nine months ended September 30, 2014 reflect an increase in the Utility's revenues beginning from January 1, 2014, as authorized in the CPUC's final decision issued in the Utility's 2014 GRC on August 14, 2014. (See "Results of Operations" below.)

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 same period in prior year (see "Results of Operations" below for additional information):

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions, except per share amounts)	Earnings	EPS (Diluted)	Earnings	EPS (Diluted)
Income Available for Common Shareholders - 2013	$161	$0.36	$728	$1.65
Natural gas matters (1)	220	0.49	193	0.45
2014 GRC expense recovery (2)	139	0.28	98	0.21
Tax benefit – repairs method and forecast change (3)	83	0.18	86	0.18
Growth in rate base earnings (4)	68	0.14	79	0.17
Timing of taxes and other expenses (5)	82	0.17	68	0.15
Gain on disposition of SolarCity stock	14	0.03	27	0.06
Regulatory matters	11	0.02	11	0.02
Gas transmission revenues	2	-	7	0.02
Increase in shares outstanding (6)	-	(0.05)	-	(0.13)
Other	30	0.09	8	0.01
Income Available for Common Shareholders - 2014	$811	$1.71	$1,305	$2.79

(1) Represents the decrease in net costs related to natural gas matters during the three and nine months ended September 30, 2014 as compared to the same periods in 2013. These amounts are not recoverable through rates. See "Operating and Maintenance" below.

(2) In 2013, the Utility incurred approximately $200 million of expense and $1 billion of capital costs above authorized levels. The 2014 GRC decision authorized revenues that support this higher level of spending in 2014 and throughout the GRC period. The amounts in the table represent the higher authorized revenue recognized during the three and nine months ended September 30, 2014, for the recovery of these expenses and costs.

(3) Represents the favorable impact of recent IRS guidance and other forecast changes on the flow-through ratemaking treatment as authorized in the 2014 GRC for federal tax deductions resulting from temporary differences attributable to repairs and certain other property-related costs. See "Income Tax Provision" below.

(4) Represents the impact of the increase in rate base as authorized in various rate cases, including the 2014 GRC, during the three and nine months ended September 30, 2014 as compared to the same periods in 2013.

(5) Represents the timing of taxes reportable in quarterly financial statements, nuclear refueling, and other expenses.

(6) Represents the impact of a higher number of weighted average shares of common stock outstanding during the three and nine months ended September 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.

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 Outcome of Pending Investigations and Enforcement Matters. The assigned CPUC ALJs overseeing the three pending investigative enforcement proceedings have issued decisions that would impose total fines and disallowances of $1.4 billion on the Utility. At September 30, 2014, the Condensed Consolidated Balance Sheets included an accrual of $200 million for the minimum amount of fines deemed probable. The Utility and other parties have appealed the decisions and several Commissioners have requested reviews of the decisions. It is uncertain when the outcome of these investigations will be determined. PG&E Corporation and the Utility believe the final outcome of the investigations will have a material impact on their financial condition, results of operations, and cash flows. (See "Pending CPUC Investigations" below.) There is also a pending federal criminal indictment against the Utility alleging that the Utility knowingly and willfully violated the Pipeline Safety Act and illegally obstructed the NTSB's investigation into the cause of the San Bruno accident. Based on the superseding indictment's allegations, the maximum statutory fine would be $14 million and the maximum alternative fine would be approximately $1.13 billion. (See "Federal Criminal Indictment" below.) Federal and state authorities also have begun investigations in connection with certain communications between the Utility and CPUC personnel. Fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to these and other enforcement matters. (See "Other Enforcement Matters" below.)

- The Timing and Outcome of Ratemaking Proceedings. The CPUC's recent decision in the 2014 GRC set revenue requirements for the Utility's electric and natural gas distribution and electric generation operations from 2014 through 2016. (See "Results of Operations" and "2014 GRC" below.) The CPUC will determine revenue requirements for the Utility's gas transmission and storage operations from 2015 through 2017 in the 2015 GT&S rate case. (The CPUC has previously issued an order to allow any revenue requirement changes adopted in the final GT&S decision to become effective on January 1, 2015.) The Utility is seeking an increase in its 2015 revenue requirements of $555 million over the comparable authorized revenues, as well as attrition increases for 2016 and 2017. It is uncertain whether and how the final outcome of the pending CPUC investigations and the CPUC enforcement actions with respect to the Utility's violations of the ex parte communication rules will affect the timing and outcome of the 2015 GT&S rate case. (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. In addition, it is uncertain how the current or potentially worsening state regulatory environment will affect the timing and outcome of these proceedings.

- The Ability of the Utility to Control Operating Costs and Capital Expenditures. Net income is impacted when costs incurred to provide utility services differ from authorized revenues. 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.) 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 authorized in the final 2014 GRC decision and future rate case decisions. (See "Ratemaking and Other Regulatory Proceedings" below.) The Utility also forecasts that in 2014 it will incur unrecovered pipeline-related expenses ranging from $350 million to $400 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 additional charges for PSEP capital if the Utility's cost forecasts increase or the CPUC orders additional disallowances. (See "Pipeline Safety Enhancement Plan" below.) The final outcome of the pending CPUC investigations and the CPUC enforcement actions with respect to the Utility's violations of the ex parte communication rules also could affect the ultimate amount of unrecovered pipeline costs.

· 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 nine months ended September 30, 2014, PG&E Corporation issued $743 million of common stock and made equity contributions to the Utility of $705 million. PG&E Corporation forecasts that it will continue issuing a material amount of equity, 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 "Enforcement and Litigation 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 available for common shareholders for the three and nine months ended September 30, 2014 and 2013:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2014	2013	2014	2013
Consolidated Total	$811	$161	$1,305	$728
PG&E Corporation	21	2	44	10
Utility	$790	$159	$1,261	$718

PG&E Corporation's net income consists primarily of interest expense on long-term debt, other income from investments, and income taxes. For the three and nine months ended September 30, 2014, results include realized gains and associated tax benefits on SolarCity investments of approximately $25 million and $45 million, respectively, with no similar activity in 2013.

Utility

The tables below show certain items from the Utility's Condensed Consolidated Statements of Income for the three and nine months ended September 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.

For the three and nine months ended September 30, 2014, results reflect the increase in authorized revenues from January 1, 2014 that were approved by the CPUC in the 2014 GRC decision issued on August 14, 2014. (See "Utility Revenues and Costs that Impact Earnings" below.)

	Three Months Ended September 30, 2014			Three Months Ended September 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	$1,979	$2,033	$4,012	$1,620	$1,897	$3,517
Natural gas operating revenues	643	284	927	454	203	657
Total operating revenues	2,622	2,317	4,939	2,074	2,100	4,174
Cost of electricity	-	1,782	1,782	-	1,645	1,645
Cost of natural gas	-	134	134	-	131	131
Operating and maintenance	892	401	1,293	1,259	324	1,583
Depreciation, amortization, and decommissioning	671	-	671	523	-	523
Total operating expenses	1,563	2,317	3,880	1,782	2,100	3,882
Operating income	1,059	-	1,059	292	-	292
Interest income (1)			1			2
Interest expense (1)			(171)			(172)
Other income, net (1)			19			20
Income before income taxes			908			142
Income tax provision (benefit) (1)			115			(20)
Net income			793			162
Preferred stock dividend requirement (1)			3			3
Income Available for Common Stock			$790			$159

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

	Nine Months Ended September 30, 2014			Nine Months Ended September 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	$5,200	$5,044	$10,244	$4,808	$4,564	$9,372
Natural gas operating revenues	1,569	967	2,536	1,336	912	2,248
Total operating revenues	6,769	6,011	12,780	6,144	5,476	11,620
Cost of electricity	-	4,341	4,341	-	3,817	3,817
Cost of natural gas	-	694	694	-	656	656
Operating and maintenance	2,935	976	3,911	3,172	1,003	4,175
Depreciation, amortization, and decommissioning	1,765	-	1,765	1,542	-	1,542
Total operating expenses	4,700	6,011	10,711	4,714	5,476	10,190
Operating income	2,069	-	2,069	1,430	-	1,430

Interest income (1)	6	6
Interest expense (1)	(535)	(513)
Other income, net (1)	56	66
Income before income taxes	1,596	989
Income tax provision (1)	325	261
Net income	1,271	728
Preferred stock dividend requirement (1)	10	10
Income Available for Common Stock	$1,261	$718

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

Utility Revenues and Costs that Impact Earnings

The following discussion presents the Utility’s operating results for the three and nine months ended September 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 $548 million, or 26%, and by $625 million, or 10%, in the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013. During the three and nine months ended September 30, 2014, the Utility recorded an increase to base revenues of $345 million, reflecting the year-to-date portion of the annual increase authorized by the CPUC in the 2014 GRC decision. This increase reflects approximately $230 million related to the six months ended June 30, 2014. The GRC decision also resulted in higher base revenues of $112 million for the three and nine months ended September 30, 2014 related primarily to the Department of Energy settlement in 2012 for spent nuclear fuel storage costs, of which $75 million pertained to the six months ended June 30, 2014. (See “Ratemaking and Other Regulatory Proceedings” below.) Additionally, operating revenues increased due to certain PSEP-related costs authorized by the CPUC, increases in base revenues as authorized by the FERC in the electric transmission owner rate case, and other higher gas transmission revenues resulting from additional demand for gas-fired generation.

Operating and Maintenance

The Utility’s operating and maintenance expenses that impacted earnings decreased by $367 million, or 29%, and by $237 million, or 7%, in the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013. The decreases are primarily due to lower net costs incurred in connection with natural gas matters (see table below).

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

	Three Months Ended September 30,		Nine Months Ended September 30,		
(in millions)	2014	2013	2014	2013	Cumulative September 30, 2014
Pipeline-related expenses (1)	$108	$113	$245	$249	$1,655
Disallowed capital (2)	-	196	-	196	549
Accrued fines (3)	-	-	-	-	239
Third-party liability claims (4)	-	110	-	110	565
Insurance recoveries (5)	(86)	(25)	(86)	(70)	(440)
Contribution to City of San Bruno	-	-	-	-	70
Total natural gas matters	$22	$394	$159	$485	$2,638

(1) Includes $112 million for work performed under the PSEP and $103 million for other gas safety-related work for the nine months ended September 30, 2014. See “Enforcement and Litigation Matters” below.
(2) See “Pipeline Safety Enhancement Plan” below.
(3) See “Pending CPUC Investigations” below.
(4) 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 September 30, 2014. In addition, the Utility has incurred cumulative expenses of $89 million for associated legal costs.

(5) The Utility has recognized cumulative insurance recoveries of $440 million for third-party claims and associated legal costs. The Utility has been engaged in settlement negotiations with its insurers regarding recovery of its remaining claims and costs.

In 2014, there have been no additional charges related to natural gas matters for disallowed capital, fines or third-party liability 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 $400 million.

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by $148 million, or 28%, and by $223 million, or 14%, in the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013, primarily due to an increase in depreciation rates as authorized by the CPUC in the 2014 GRC decision and an increase in 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 2014 GRC decision authorized flow-through ratemaking for temporary differences attributable to repair costs and certain other property-related costs for federal tax purposes. The Utility's financial results reflect a reduction in income tax expense associated with these temporary differences consistent with this ratemaking method. (See "2014 GRC" in "Ratemaking and Other Regulatory Proceedings" below.)

The Utility's income tax provision increased by $135 million and $64 million in the three and nine months ended September 30, 2014, respectively, compared to the same periods in 2013. The increases in the tax provision were primarily due to higher pre-tax income, partially offset by certain reductions in tax expense for flow-through treatment as discussed above. The following table reconciles the income tax expense at the federal statutory rate to the income tax provision:

	Three Months Ended September 30,				Nine Months Ended September 30,			
	2014		2013		2014		2013	
Federal statutory income tax rate	35.0	%	35.0	%	35.0	%	35.0	%
Increase (decrease) in income tax rate resulting from:								
State income tax (net of federal benefit) (1)	2.9		(25.0	)	1.9		(2.1	)
Effect of regulatory treatment of fixed asset differences (2)	(19.9	)	(10.1	)	(13.0	)	(2.9	)
Tax credits	(0.4	)	(1.6	)	(0.5	)	(0.4	)
Benefit of loss carryback	0.2		(1.9	)	(0.2	)	(0.2	)
Other, net (3)	(5.2	)	(10.4	)	(2.8	)	(3.0	)
Effective tax rate	12.6	%	(14.0	) %	20.4	%	26.4	%

(1) Includes the effect of state flow-through ratemaking treatment. Additionally, during the three months ended September 30, 2013, the Utility recorded an adjustment to state income taxes in connection with an IRS settlement.
(2) Represents effect of federal flow-through ratemaking treatment including those deductions related to repairs and certain other property-related costs discussed above.
(3) Primarily relates to research and development tax credits and other timing differences.

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.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2014	2013	2014	2013
Cost of purchased power	$ 1,684	$ 1,560	$ 4,083	$ 3,590
Fuel used in own generation facilities	98	85	258	227
Total cost of electricity	$ 1,782	$ 1,645	$ 4,341	$ 3,817
Average cost of purchased power per kWh (1)	$ 0.114	$ 0.101	$ 0.101	$ 0.092
Total purchased power (in millions of kWh)	14,724	15,459	40,512	39,133

(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 Utility must inform the CPUC, and the CPUC may authorize an adjustment to retail electricity generation rates before the next annual update. In the three months ended September 30, 2014, the Utility exceeded the five percent balance. The Utility filed an application notifying the CPUC that the threshold was met. In a separate application, the Utility sought authority to recover the under-collected amounts as part of its annual adjustment to retail electricity generation rates, starting on 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 September 30,		Nine Months Ended September 30,	
(in millions)	2014	2013	2014	2013
Cost of natural gas sold	$ 102	$ 96	$ 591	$ 533
Transportation cost of natural gas sold	32	35	103	123
Total cost of natural gas	$ 134	$ 131	$ 694	$ 656

Average cost per Mcf (1) of natural gas sold	$ 3.78	$ 3.43	$ 4.13	$ 3.14
Total natural gas sold (in millions of Mcf)	27	28	143	170

(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 other enforcement matters, and will also be affected by various other factors described in "Operating Activities" below. The Utility's equity needs will 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 "Enforcement and Litigation 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 reduced 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

The following senior notes were issued during 2014:

(in millions)	Issuance Date	Principal Amount		Maturity Date
PG&E Corporation				
2.40% Senior Notes	February 2014	$350	(1)	March 1, 2019
Utility				
Floating Rate Senior Notes	May 2014	300	(2)	May 11, 2015
3.75% Senior Notes	February 2014	450	(3)	February 15, 2024
3.40% Senior Notes	August 2014	350	(4)	August 15, 2024
4.75% Senior Notes	February 2014	450	(3)	February 15, 2044
4.75% Senior Notes	August 2014	225	(4)	February 15, 2044
Total senior note issuances		$2,125		

(1) The proceeds were used to repay the 5.75% Senior Notes, in the principal outstanding amount of $350 million.
(2) The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.
(3) 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.
(4) The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper, and to fund capital expenditures.

PG&E Corporation 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. During the three and nine months ended September 30, 2014, PG&E Corporation sold 2 million and 11 million shares, respectively, under the February 2014 equity distribution agreement for cash proceeds of $67 million and $496 million, respectively, exhausting the remaining capacity under this agreement. These amounts are net of commissions paid of $1 million and $4 million, respectively.

In addition, PG&E Corporation issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During the nine months ended September 30, 2014, 7 million shares were issued for cash proceeds of $247 million under these plans.

The proceeds from these sales were used for general corporate purposes, including the infusion of equity into the Utility. For the nine months ended September 30, 2014, PG&E Corporation made equity contributions to the Utility of $705 million. PG&E Corporation forecasts that it will need to continue to issue additional common stock to fund the Utility's equity needs.

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 September 30, 2014:

(in millions)	Termination Date	Facility Limit		Letters of Credit Outstanding	Commercial Paper	Facility Availability
PG&E Corporation	April 2019	$ 300	(1)	$ -	$ -	$ 300
Utility	April 2019	3,000	(2)	84	126	2,790
Total revolving credit facilities		$ 3,300		$ 84	$ 126	$ 3,090

(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 nine months ended September 30, 2014, the average outstanding borrowings under PG&E Corporation's revolving credit facility were $36 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 nine months ended September 30, 2014, PG&E Corporation's average outstanding commercial paper balance was $132 million and the maximum outstanding balance during the period was $260 million.

For the nine months ended September 30, 2014, the Utility's average outstanding commercial paper balance was $798 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 September 30, 2014, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

In September 2014, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $216 million, of which approximately $211 million was paid on October 15, 2014 to shareholders of record on September 30, 2014.

In September 2014, the Board of Directors of the Utility declared a common stock dividend of $179 million that was paid to PG&E Corporation on September 17, 2014.

In September 2014, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on November 15, 2014, to shareholders of record on October 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 nine months ended September 30, 2014 and 2013 were as follows:

	Nine Months Ended September 30,	
(in millions)	2014	2013
Net income	$1,271	$728
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,765	1,542
Allowance for equity funds used during construction	(72)	(78)
Deferred income taxes and tax credits, net	173	545
PSEP disallowed capital expenditures	-	196
Other	212	231
Net effect of changes in operating assets and liabilities	(441)	(485)
Other noncurrent assets and liabilities	6	147
Net cash provided by operating activities	$2,914	$2,826

During the nine months ended September 30, 2014, net cash provided by operating activities increased by $88 million compared to the same period in 2013. This increase was primarily due to a tax refund, additional GHG auction proceeds, and higher cash collateral returned to the Utility in 2014. The increase was partially offset by various fluctuations in other cash flows including higher purchased power costs (see "Cost of Electricity" under "Results of Operations – Utility Revenues and Costs that do not Impact Earnings" above) and lower insurance proceeds in 2014.

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

- the timing and outcome of ratemaking proceedings, including the 2015 GT&S rate case;
- the timing and amount of fines or penalties that will be imposed in connection with the pending investigations and other enforcement matters, as well as any costs associated with remedial actions the Utility may be required to implement (see "Enforcement and Litigation Matters"

below);

- the timing and amount of pipeline-related costs the Utility incurs, but does not recover, associated with its natural gas system (see “Operating and Maintenance” under “Results of Operations – Utility Revenues and Costs that Impact Earnings” above and “Pending CPUC Investigations” under “Enforcement and Litigation Matters” below);

- the timing and amount of insurance recoveries related to third-party claims (see “Operating and Maintenance” under “Results of Operations – Utility Revenues and Costs that Impact Earnings” above);

- the timing and amount of tax payments, tax refunds, net collateral payments, and interest payments; 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 nine months ended September 30, 2014 and 2013 were as follows:

	Nine Months Ended September 30,	
(in millions)	2014	2013
Capital expenditures	$(3,564)	$(3,881)
Decrease in restricted cash	2	29
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,059	1,152
Purchases of nuclear decommissioning trust investments	(1,065)	(1,150)
Other	22	14
Net cash used in investing activities	$(3,546)	$(3,836)

Net cash used in investing activities decreased by $290 million during the nine months ended September 30, 2014 as compared to the same period in 2013. This decrease was primarily due to the discontinuation of the Utility's photovoltaic program and lower PSEP-related 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 approximately $5.1 billion in capital expenditures for 2014, including PSEP-related expenditures.

Financing Activities

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

	Nine Months Ended September 30,	
(in millions)	2014	2013
Net issuances (repayments) of commercial paper, net of discount of $1 at respective dates	$(789)	$322
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 $3 and $9 at respective dates	1,472	741
Repayments of long-term debt	(539)	(461)
Preferred stock dividends paid	(10)	(10)
Common stock dividends paid	(537)	(537)
Equity contribution	705	835
Other	50	(14)
Net cash provided by financing activities	$652	$876

During the nine months ended September 30, 2014, net cash provided by financing activities decreased by $224 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.

ENFORCEMENT AND LITIGATION 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. See "Results of Operations" above.

Pending CPUC Investigations

On September 2, 2014, the assigned CPUC ALJs issued their presiding officer decisions in the three investigative enforcement proceedings pending against the Utility. As previously disclosed in the 2013 Annual Report, these investigations relate to the Utility's natural gas transmission operations and practices and the San Bruno accident. The ALJs determined that the Utility committed approximately 3,700 violations of law, rules and regulations. The ALJs jointly issued a decision (the "Penalty Decision") calling for total penalties of $1.4 billion on the Utility to address all violations, allocated as follows: (1) $950 million fine to be paid to the State General Fund, (2) $400 million refund to ratepayers of previously authorized revenues, and (3) remedial measures that the ALJs estimate will cost the Utility at least $50 million. See table below. The ALJs' decisions are not the final decisions of the CPUC. As described below, the Utility and other parties have appealed these decisions. In addition, three CPUC Commissioners have requested that the CPUC review the decisions. It is possible that one or more Commissioners will issue an alternate penalty decision for consideration by the CPUC. (Two of the five CPUC Commissioners have recused themselves from voting on the final outcome of the investigations.)

On October 2, 2014, the Utility and other parties, including TURN, ORA, and CCSF filed appeals with the CPUC of the presiding officer decisions. In its appeals, the Utility argues that the penalties imposed and the findings and conclusions on which they are based do not meet applicable legal standards, are based on the misapplication of California law and regulations, and are unconstitutional. The Utility asked the CPUC to order the Utility to pay a significantly reduced penalty that is reasonable and proportionate in light of the nature of the violations and that takes into account the substantial unrecovered amounts the Utility has already spent and forecasts that it will spend on gas system safety. The Utility requests that it be allowed 180 days to raise the funds it may be ordered to pay to the State General Fund rather than the 40 days specified in the Penalty Decision. The Utility also argues that the entire penalty should go toward funding investments in the Utility's gas transmission system.

TURN, ORA, and CCSF jointly filed an appeal urging the CPUC to disallow the Utility's recovery of remaining PSEP costs of $877 million and to require the Utility to pay $473 million to the State General Fund. These parties also argue that the record in the investigative proceedings would support an even larger penalty than stated in the Penalty Decision. The City of San Bruno appealed the rejection of its proposals for the appointment of an independent monitor to oversee the Utility's natural gas operations and for the establishment of a pipeline safety trust. On October 27, 2014, the parties filed responses to the various appeals.

It is uncertain when the outcome of these investigations will be determined. There continues to be significant uncertainty regarding the ultimate form and amount of penalty while the various appeals and requests for review of the presiding officer's decisions are unresolved. The impact on PG&E Corporation's and the Utility's consolidated financial statements will vary depending on the form and amount of penalties that are ultimately adopted by the CPUC. Fines payable to the State General Fund or refunds of revenues previously authorized would be charged to net income when it is probable that such penalties will be imposed and the amounts can be reasonably estimated. A disallowance of previously authorized and incurred capital costs would be charged to net income when the disallowance is probable and the amount can be reasonably estimated. (See "Pipeline Safety Enhancement Plan" below.) Penalties in the form of future shareholder-funded pipeline work would be charged to net income in the period during which the actual costs are incurred.

At September 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. Although the CPUC may impose total penalties on the Utility of $1.4 billion or higher, consistent with the Penalty Decision, the Utility is unable to make a better estimate of probable fines or make a reasonable estimate of probable disallowances or other refunds due to the variety of potential outcomes that could result from the various appeals and Commissioners' requests for review. PG&E Corporation's and the Utility's estimates and the assumptions on which they are based are subject to change as developments in the appeal process occur or if alternate penalty decisions are issued for CPUC consideration. Future changes in estimates or assumptions could have a material impact on future financial condition, results of operations, and cash flows. PG&E Corporation and the Utility believe the final outcome of the investigations will have a material impact on their financial condition, results of operations, and cash flows.

If the Penalty Decision becomes final, the Utility estimates that its total pre-tax unrecovered costs and fines related to natural gas transmission operations would be about $4.75 billion based on current forecasts, allocated as follows:

Description of Component:	Amounts (in millions)
Fine payable to the State General Fund	$950
Refund of PSEP revenues previously authorized	400
Additional estimated unrecoverable costs (1)	50
Total penalty	1,400
PSEP costs previously disallowed	635
Total penalty and PSEP cost disallowance	2,035
Gas pipeline safety costs incurred or committed (2)	2,700
Less: Credit for PSEP costs previously disallowed	(635)
Total estimated shareholder impact before non-deductibility of fines	4,100
Estimated impact of non-deductibility of fines for tax purposes (3)	650
Total estimated shareholder impact (pre-tax)	$4,750

(1) The Penalty Decision estimates that the Utility would incur at least $50 million to implement remedial measures. Actual costs could differ materially based on the scope and timing of work. In addition, the Penalty Decision requires shareholders to reimburse interveners for legal and litigation expenses.
(2) Actual and forecast costs borne by shareholders for gas pipeline safety work, 2010 and beyond, including previously disallowed PSEP costs. The forecast of costs included in this amount constitutes a forward-looking statement and actual results could differ materially based on the actual scope and timing of planned or required work. See “Cautionary Language Regarding Forward-Looking Statements” below.
(3) Estimated impact calculated based on the Utility’s statutory tax rate.

Federal 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 illegally obstructed the NTSB’s investigation of the San Bruno accident. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also seeks an 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.” Based on the superseding indictment’s allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. 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. A status conference is scheduled to be held in court on November 3, 2014. 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 considered to be probable. 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 final penalties.

Improper CPUC Communications

In September and October 2014, the Utility notified the CPUC that the Utility believes certain communications between the Utility and CPUC personnel violated the CPUC's rules regarding ex parte communications. Ex parte communications include any communications concerning substantive issues in a formal proceeding before the CPUC, between a decision maker and an interested person, that does not occur in an established public forum or on the record. Some of these communications relate to the GT&S rate case. On October 16, 2014, a CPUC ALJ issued a ruling, effective immediately, that bans the Utility from engaging in any oral or written ex parte communications, as well as procedural communications, with Commissioners or their advisors (other than during all-party meetings) regarding the GT&S rate case or any other rate-setting or adjudicatory proceeding before the CPUC, for a one-year period or until the resolution of the GT&S rate case, whichever is later. (The ALJ also issued a PD requesting the CPUC to affirm the ruling.) In addition, the CPUC Commissioner who is assigned to the GT&S rate case issued an alternate PD on October 16, 2014, that, among other provisions, would impose a $1.05 million fine and adopt a ratemaking disallowance of no more than half of the revenue increase, as authorized by a final CPUC decision in the 2015 GT&S rate case, that would have been amortized (collected from ratepayers) over the period between the original planned timing of a final decision (March 2015) and the modified schedule for a final decision. Comments by parties on the PD and alternate PD are due on November 5, 2014.

Neither the PD nor the alternate PD address the additional ex parte communications that the Utility identified and reported to the CPUC on October 6, 2014. The Utility believes it is probable that CPUC enforcement actions will be taken in connection with these additional ex parte communications.

In addition, the U.S. Attorney's Office in San Francisco and the California Attorney General's office have begun investigations in connection with these communications. The Utility is cooperating with the federal and state investigators. It is uncertain whether any charges will be brought against the Utility.

It is uncertain whether these communication issues will affect other ongoing legal and regulatory matters, including the other enforcement actions pending against the Utility, the GT&S rate case, or the CPUC's consideration of the settlement reached among the parties to authorize revenues associated with the Utility's PSEP Update application. Further, other proceedings, investigations, or legal actions could be commenced with respect to these issues which could cause additional reputational harm and could result in the imposition of additional penalties on the Utility. (See "2015 GT&S Rate Case" and "Item 1A. Risk Factors" below.)

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 "Ratemaking and Other Regulatory Proceedings" 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.

As of September 30, 2014, the Utility has submitted 70 self-reports (plus several follow-up reports) that the SED has not yet addressed. Among other reports, 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 has notified the SED that employees who are performing this work have undergone the 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.

Carmel Incident

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 U.S. Attorney's Office is investigating the Carmel incident and the Utility is cooperating with federal investigators. The CPUC and local Carmel officials are also continuing to investigate the incident. The City of Carmel has requested the CPUC to issue an order instituting a formal investigation into whether the Utility violated applicable laws and regulations. The Utility believes it is probable that enforcement actions will be taken in connection with this matter.

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.

Kern Power Plant

On August 28, 2014, the CPUC issued an order instituting a formal investigation into a contract worker fatality that occurred in June 2012 during the dismantling of an unused fuel tank at the Utility's retired Kern power plant in Bakersfield, California. The SED conducted an investigation of the incident and has alleged that the Utility failed to adequately evaluate safety in contract bid proposals; did not provide adequate contractor project safety review and oversight; and neglected to evaluate safer alternatives. The SED also alleged that the Utility failed to conduct a prompt and thorough incident root cause analysis, as requested by the SED, in order to assist in identifying and implementing effective corrective actions to improve safety and reduce the likelihood of future incidents. The CPUC also noted that the SED's investigation into a 2013 incident at the Kern power plant is ongoing. In that incident, a bystander who was observing the demolition of the plant was severely injured by debris from the explosion.

The Utility and the SED are currently engaged in negotiations to reach a stipulated outcome of this proceeding. The CPUC ALJ has deferred adoption of a procedural schedule to enable the parties to continue to engage in negotiations. Any settlement agreement that may be reached would be submitted to the CPUC for its consideration. The Utility and the SED are scheduled to file a status report with the ALJ on November 3, 2014. It is reasonably possible that fines will be imposed on the Utility in connection with this matter. The CPUC also could order the Utility to comply with additional remedial measures, such as requiring the Utility to correct identified deficiencies and to further improve the safety of its operations.

Pipeline Safety Enhancement Plan

On October 16, 2014, a PD was issued that would approve the settlement agreement (submitted in July 2014) among the Utility, the CPUC's ORA and TURN, to resolve the Utility's PSEP Update application (submitted in October 2013). The total PSEP-related revenue requirements (2012-2014) proposed in the settlement agreement reflect a proposed $23 million reduction to expense funding, as compared to the Utility's request. The Utility has recorded a charge against operating revenue to reflect the cumulative impact of this reduction. There would be no 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 September 30, 2014, approximately $540 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 in its final decision. Comments on the PD are due November 5, 2014. The CPUC will vote on the PD, at the earliest, on November 20, 2014. The Utility's ability to recover PSEP-related costs also could be affected by final decisions issued in the CPUC's pending investigations discussed above.

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 order instituting the rulemaking noted that the CPUC's current gas safety enforcement program appears to satisfy the law's requirements. (See "Other Enforcement Matters" above about the reports the Utility has filed to notify the CPUC staff of noncompliance with certain gas safety regulations.) The CPUC has indicated its plans to bifurcate the proceeding into two phases to allow for adoption of an interim electric safety citation program by the January 1, 2015 deadline. A proposed decision is anticipated for the first phase in 2014. The second phase will review both the natural gas and electric citation programs to determine what modifications, if any, may be needed so that they may work more effectively and efficiently.

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.

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 alleged 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 alleged that PG&E Corporation and the Utility engaged in unfair business practices in violation of California state law. The plaintiffs sought restitution and disgorgement, as well as compensatory and punitive damages. 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. In October 2014, the Court of Appeal affirmed the court's ruling to dismiss the complaint. PG&E Corporation and the Utility believe it is remote that any material losses will be incurred in connection with this complaint.

Other Pending Lawsuits and Claims

At September 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, which has been amended to discuss recent events, including the federal criminal indictment discussed above. In August 2014, the judge lifted the stay on the consolidated complaint and allowed litigation to resume. On September 15, 2014, PG&E Corporation, the Utility and the individual defendants asked the court to dismiss the consolidated complaint because the plaintiffs (1) failed to demand that the Boards of Directors pursue claims against the directors and officers and (2) have not pled why such demand should be excused. The requests for dismissal will be heard by the court on November 13, 2014. On September 22, 2014, PG&E Corporation, the Utility, and the individual defendants filed a petition with the California Court of Appeal requesting a new order continuing the stay until resolution of the federal criminal indictment discussed above. 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.

RATEMAKING AND OTHER REGULATORY PROCEEDINGS

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

On August 14, 2014, the CPUC issued a final decision in the Utility's 2014 GRC, authorizing the Utility to collect a total 2014 revenue requirement of approximately $7.1 billion to recover anticipated costs associated with electric generation, and electric and natural gas distribution. This reflects an overall increase of $460 million, or 6.9%, over previously authorized amounts. The CPUC also authorized attrition increases of $324 million for 2015 and $371 million for 2016. The CPUC approved the Utility's request to recover actual costs associated with gas leak survey and repair (subject to a limit based on the Utility's forecast of costs to perform an accelerated three-year leak survey), major emergencies, and certain new regulatory requirements related to nuclear operations and hydroelectric relicensing. The following table shows the differences between the Utility's requested increases in 2014 revenue requirements and the final adopted increase by line of business:

(in millions)	Final Decision	Requested by the Utility	Difference
Line of business			
Electric distribution	$125	$514	$(389)
Gas distribution	264	446	(182)
Electric generation	71	200	(129)
Total revenue increase	$460	$1,160	$(700)

For 2014, the CPUC authorized capital expenditures of approximately $3.5 billion and a weighted average rate base of $20.5 billion. The adopted revenue requirement included 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 adopted revenue requirement also included offsets of $150 million, primarily related to a customer refund of funds the Utility received from the Department of Energy pursuant to a 2012 settlement for costs incurred to store spent nuclear fuel. These funds were previously deferred as a refund obligation.

The 2014 GRC decision also authorized flow-through ratemaking for temporary differences attributable to the deductibility of repair costs and certain other property-related costs for federal tax purposes. PG&E Corporation's and the Utility's financial results reflect a reduction in income tax expense associated with these temporary differences consistent with this ratemaking method. In addition, recent guidance from the IRS allows the Utility to deduct more repair costs than previously forecasted in the GRC. For the three months ended September 30, 2014, the Utility recognized a reduction in income tax expense consistent with GRC and IRS guidance for $175 million for the application of flow-through ratemaking effective as of January 1, 2014.

The 2014 revenue requirement increase authorized by the decision is effective beginning January 1, 2014. PG&E Corporation's and the Utility's financial results for the quarter ending September 30, 2014 reflect the portion of the annual increase attributable to the nine months ended September 30, 2014. (See "Results of Operations" above.) Gas and electric rates have been adjusted to recover the increase in authorized revenue requirements beginning September 1 and October 1, respectively.

2015 Gas Transmission and Storage Rate Case

Utility's Request and Intervenor Testimony

As previously disclosed in the 2013 Annual Report, the Utility has requested that the CPUC authorize a 2015 revenue requirement of $1.29 billion to recover anticipated costs of providing natural gas transmission and storage services, an increase of $555 million over currently authorized amounts. In August 2014, the ORA, TURN, and other parties, submitted testimony in response to the Utility's request. The ORA recommended a 2015 revenue requirement of $1,053 million, an increase of $338 million over currently authorized amounts. The ORA recommended attrition increases of $39 million for 2016 and $61 million for 2017, compared to the Utility's requested attrition increases of $61 million for 2016 and $168 million for 2017. The ORA also recommended that the GT&S rate case period be expanded to four years with an attrition increase of $35 million for 2018. The ORA recommended that the CPUC authorize 2015 capital expenditures of $591 million, compared to the Utility's request of $779 million.

TURN was critical of the Utility's request and stated that it would make its specific revenue requirement recommendation in its opening brief. TURN has recommended that the Utility not recover costs associated with hydrostatic testing for pipeline segments placed in service between January 1, 1956 and June 30, 1961, as well as certain other work that TURN considers to be remedial. (The Utility has not requested rate recovery for pressure testing of pipelines placed into service after 1961.) TURN also recommended the disallowance of about $200 million of capital expenditures incurred over the period 2011 through 2014 and recommended that about $500 million of these capital expenditures be subject to a reasonableness review and an independent audit. TURN states that the Utility's cost recovery should not begin until the CPUC issues a decision on the independent audit.

Parties, including ORA and TURN, have recommended that the CPUC reject the Utility's request for a two-way balancing account for costs associated with pipeline integrity management activities. An association of large shippers that use the Utility's natural gas pipeline system has recommended that many of the Utility's costs be subject to a CPUC reasonableness review. TURN and other parties, including the association of large shippers, have proposed that the amortization period of certain investments be extended, and that the Utility's rate of return on equity associated with certain capital costs be reduced.

Improper CPUC Communications

As described above in "Enforcement and Litigation Matters", the Utility has notified the CPUC that it believes certain communications between the Utility and CPUC personnel relating to the 2015 GT&S rate case violated the CPUC's rules regarding ex parte communications. On October 16, 2014, a CPUC ALJ issued a ruling, effective immediately, that bans the Utility from engaging in any oral or written ex parte communications, as well as procedural communications, with Commissioners or their advisors (other than during all-party meetings) regarding the GT&S rate case or any other rate-setting or adjudicatory proceeding before the CPUC, for a one-year period or until the resolution of the GT&S rate case, whichever is later. (The ALJ also issued a PD requesting the CPUC to affirm the ruling.) In addition, the CPUC Commissioner who is assigned to the GT&S rate case issued an alternate PD that, among other provisions, would adopt a ratemaking disallowance of no more than half of the revenue increase, as authorized by a final CPUC decision in the 2015 GT&S rate case, that would have been amortized (collected from ratepayers) over the period between the original planned timing of a final decision (March 2015) and the modified schedule for a final decision. Comments on the PD and alternate PD are due on November 5, 2014.

Procedural Schedule

In connection with the prohibited ex parte communications above, the CPUC's acting chief ALJ temporarily suspended the procedural schedule, which had previously called for a final decision to be issued in March 2015, and also assigned a new ALJ to oversee the proceeding. It is uncertain when a new procedural schedule will be issued. Intervening parties have proposed various protracted schedules, including a proposal that anticipates a final decision as late as October 1, 2015. The CPUC has previously issued an order to allow any revenue requirement changes adopted in the final GT&S decision to become effective on January 1, 2015.

Regulatory Accounting

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 September 30, 2014, the FERC accepted the rate case application that the Utility filed on July 30, 2014, making the proposed rates effective March 1, 2015, subject to refund, pending a final decision by the FERC. The Utility requested a 2015 retail electric transmission revenue requirement of $1,366 million, a $326 million increase to the settled revenue requirement that is pending FERC approval, as 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. Proposed rate base for 2015 is $5.12 billion compared to $4.57 billion in 2014. The Utility has requested that the FERC approve an 11.26% ROE. The procedural schedule is currently being held in abeyance while settlement discussions are held.

Electricity Rate Reform

New state legislation that became effective on January 1, 2014 (AB 327) grants the CPUC authority to approve fixed charges to be collected from residential customers. In 2012, the CPUC began a rulemaking proceeding 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 and retail rates that do not reflect PG&E's cost structure, has shifted costs to remaining customers. AB 327 gives the CPUC new authority to reduce the cost shift associated with renewable distributed generation through residential rate and net energy metering reform. 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 is expected to issue a scoping memo before the end of 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.

Diablo Canyon Nuclear Power Plant

The NRC oversees the licensing, construction, operation, and the eventual decommissioning of the Utility's Diablo Canyon nuclear power plant, located near San Luis Obispo, California. The NRC operating licenses for the two operating units at Diablo Canyon include various license conditions related to seismic design and safety. The current licenses expire in 2024 and 2025. In November 2009, the Utility filed an application with the NRC to seek the renewal of the licenses, a process which can take several years. As previously disclosed, after the March 2011 Fukushima-Dai-ichi event, the NRC granted the Utility’s request to delay processing its renewal application until certain advanced seismic studies of the fault zones in the region surrounding Diablo Canyon were completed. The seismic studies have been completed and in September 2014, the Utility submitted a report to the NRC and the CPUC’s Independent Peer Review Panel that confirmed the seismic safety of the plant. The Independent Review Panel has stated that it will review and provide comments on the report over the next six to eight months. The NRC has not yet issued a public schedule for review of the report.

Oakley Generation Facility

As previously disclosed, in February 2014, the California Court of Appeal issued a ruling that annulled the CPUC's December 2012 decision to approve the amended purchase and sale agreement that the Utility had entered into with a third-party developer for the construction and acquisition of the 586-megawatt natural gas-fired facility in Oakley, California. The agreement permits the Utility to terminate the agreement if final non-appealable CPUC approval was not received by July 1, 2014. On October 15, 2014, the Utility notified the third-party developer that the Utility was exercising its right to terminate the agreement. On October 17, 2014, the Utility received a notice of dispute from the third-party developer starting the dispute resolution process.

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 September 30, 2014, $163 million and $294 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. The EPA is expected to issue final regulations by June 2015. 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. 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 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. (See "Commitments" in Note 10 of the Notes to the Condensed Consolidated Financial Statements). Contractual commitments that relate to financing arrangements include long-term debt, preferred stock, and certain forms of regulatory financing. For more in-depth discussion about PG&E Corporation's and the Utility's contractual commitments, see "Liquidity and Financial Resources" above and Management's Discussion and Analysis – Contractual Commitments in the 2013 Annual Report.

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 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 nine months ended September 30, 2014.

CRITICAL ACCOUNTING POLICIES

The preparation of the Condensed Consolidated Financial Statements in accordance with 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 pipeline-related expenses 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," "antic "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, the federal criminal prosecution of the Utility, and other investigations relating to the Utility's compliance with laws and regulations, including the ultimate amount of fines imposed, whether a monitor is appointed to oversee the Utility's natural gas operations, and the ultimate amount of costs the Utility incurs that are not recoverable or are disallowed including the cost of required remedial actions;

- the timing and outcome of additional regulatory enforcement actions or criminal investigations that may be or have been commenced relating to the Utility's natural gas operating practices or compliance with the CPUC's rules regarding ex parte communications and whether such additional actions or investigations negatively affect the outcome of ratemaking proceedings, such as the 2015 GT&S rate case, or the pending CPUC investigations;

- 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 CPUC rules regarding ex parte communications, and the ongoing work to remove encroachments from transmission pipeline rights-of-way;

- the timing and outcome of pending ratemaking proceedings (such as 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; and whether the current or potentially worsening state regulatory environment increases the likelihood of unfavorable outcome;

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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;

- the impact that reductions in customer demand for electricity and natural gas (resulting from the growth in self-generation technologies (primarily residential rooftop solar) and other distributed generation and energy storage technologies; changing levels of customers who procure electricity from alternative electricity providers or community choice aggregators; changing levels of customers who procure natural gas from alternative gas providers, such as core transport agents; municipalization of the Utility's electric or gas distribution facilities; and general and regional economic and financial market conditions) have on the Utility's ability to recover its investments through rates and earn its authorized ROE;

- 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;

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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 "Enforcement and Litigation 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 September 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 September 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.

Pending CPUC Investigations

On September 2, 2014, the assigned CPUC ALJs issued their presiding officer decisions in the three investigative enforcement proceedings pending against the Utility. As previously disclosed, these investigations relate to the Utility's natural gas transmission operations and practices and the San Bruno accident. The ALJs determined that the Utility committed approximately 3,700 violations of law, rules and regulations. The ALJs jointly issued a decision that would impose total penalties of $1.4 billion on the Utility to address all violations. The Utility and other parties have filed appeals with the CPUC and several Commissioners have filed requests for review. It is uncertain when the outcome of these investigations will be determined. For additional information, see the discussion entitled "Enforcement and Litigation 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 Reports on Form 10-Q for the quarters ended March 31, 2014 and June 30, 2014.

Federal 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 illegally obstructed the NTSB's investigation of the San Bruno accident. The maximum statutory fine for each felony count is $500,000, for total fines of $14 million. The superseding indictment also seeks an 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." Based on the superseding indictment's allegations that the Utility derived gross gains of approximately $281 million and that the victims suffered losses of approximately $565 million, the maximum alternate fine would be approximately $1.13 billion.

The Utility entered a plea of not guilty. 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. A status conference is scheduled to be held in court on November 3, 2014. 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 considered to be probable. See the discussion in "Item 1A. Risk Factors" below.

Litigation Related to the San Bruno Accident and Natural Gas Spending

At September 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, which has been amended to discuss recent events, including the federal criminal indictment discussed above. In August 2014, the judge lifted the stay on the consolidated complaint and allowed litigation to resume. On September 15, 2014, PG&E Corporation, the Utility and the individual defendants asked the court to dismiss the consolidated complaint because the plaintiffs (1) failed to demand that the Boards of Directors pursue claims against the directors and officers and (2) have not pled why such demand should be excused. The requests for dismissal will be heard by the court on November 13, 2014. On September 22, 2014, PG&E Corporation, the Utility, and the individual defendants filed a petition with the California Court of Appeal requesting a new order continuing the stay until resolution of the federal criminal indictment discussed above. 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. 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. In October 2014, the Court of Appeal affirmed the court's ruling to dismiss the complaint.

For additional information regarding these matters, see the discussion entitled "Enforcement and Litigation 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 Reports on Form 10-Q for the quarters ended March 31, 2014 and June 30, 2014.

Other Enforcement Matters

In addition, fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the Utility's self-reports of noncompliance with natural gas safety regulations, prohibited ex parte communications between the Utility and CPUC personnel, investigations that were commenced after a pipeline explosion in Carmel, California on March 3, 2014, and other enforcement matters. See the discussion entitled "Enforcement and Litigation 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 Reports on Form 10-Q for the quarters ended March 31, 2014 and June 30, 2014.

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.

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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 continued to be significantly affected by the negative publicity about the pending CPUC investigations; the federal criminal prosecution of the Utility; the Utility's violations of the CPUC's rules regarding ex parte communications and the state and federal investigations begun in connection with ex parte communications; the Utility's self-reports of noncompliance with certain natural gas regulations; and the CPUC, local and federal investigations of the natural gas incident that occurred in Carmel, California on March 3, 2014. Their reputations could be further harmed by the ultimate outcome of the pending CPUC investigations and enforcement matters and the criminal prosecution, or if additional regulatory or enforcement action is taken with respect to the Utility's compliance with laws, regulations or orders. A potentially worsening regulatory environment also could affect the outcome of these matters and other ratemaking or regulatory proceedings. The outcome of these matters, including the total amount and forms of 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 and to implement required remedial measures, is expected to 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 pending CPUC investigations, the federal criminal prosecution of the Utility, the Utility's disclosure of violations of the CPUC's rules regarding ex parte communications, the federal and state investigations that have commenced in connection with ex parte communications, and the other matters discussed above in "Enforcement and Litigation Matters" in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations. Media coverage of future developments in these matters could cause further reputational harm. After the Utility's disclosure of improper communications with the CPUC, two of the five CPUC Commissioners recused themselves from voting on the final outcome of the pending investigations and the GT&S rate case. (See "2015 GT&S Rate Case" in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations above.) In addition, the Utility has been banned from engaging in any oral or written ex parte communications, as well as procedural communications, with Commissioners or their advisors (other than during all-party meetings) regarding the GT&S rate case or any other rate-setting or adjudicatory proceeding before the CPUC, for a one-year period or until the resolution of the GT&S rate case, whichever is later. These developments could lead to a potentially worsening regulatory environment that could make unfavorable regulatory outcomes more likely.

This continuing negative publicity, uncertainty, and potentially worsening regulatory environment, may cause investors to question management's ability to repair the reputational harm that PG&E Corporation and the Utility have suffered and execute their business strategy, resulting in an adverse impact on the market price of PG&E Corporation common stock.

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 a fine to the State General Fund that materially exceeds the $200 million previously accrued. The Penalty Decision, if ultimately upheld after the appeal and review process are completed, would impose total penalties of $1.4 billion. (See "Pending CPUC Investigations" in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations above.) It is also possible that the final decision could impose a higher amount of penalties. 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, whether the CPUC adopts the alternate PD issued by the Commissioner assigned to the GT&S rate case to disallow a portion of the revenues that may be authorized in the final GT&S rate case decision, the extent to which the scope and timing of planned pipeline work changes, and whether actual costs exceed forecasts.

Finally, 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. Further, the Utility could be required to pay fines or incur other costs in connection with additional federal or state enforcement action that may be taken with respect to the improper communications with the CPUC and the other matters discussed under “Enforcement and Litigation Matters--Other Enforcement Matters” in Part I, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations above.

PG&E Corporation's and the Utility's financial condition depends upon the Utility's ability to recover its operating expenses, its electricity and natural gas procurement costs, and earn a reasonable rate of return on capital investments, in a timely manner from the Utility's customers through regulated rates. There will likely be differences between the forecasts of revenues and costs used when rates are set and actual revenues and costs and these differences could directly affect net income. Further, as the deployment of new electricity generation and storage technologies spreads and becomes more cost-effective, the Utility's ability to recover its investments and earn its authorized ROE can be adversely affected unless rates are timely adjusted.

The Utility's ability to recover its costs and earn its authorized rate of return can be affected by many factors, including the time lag between when costs are incurred and when those costs are recovered in customers' rates and differences between the forecast or authorized costs embedded in rates (which are set on a prospective basis) and the amount of actual costs incurred. (See "2014 General Rate Case" in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations above.) The CPUC or the FERC may not allow the Utility to recover costs on the basis that such costs were not reasonably or prudently incurred or for other reasons. For example, the CPUC has prohibited the Utility from recovering a material portion of costs that the Utility has already incurred, and will continue to incur, as it performs work under the PSEP and the ultimate outcome of the pending CPUC investigations may impose further disallowances or require customer refunds to be made. In other instances, the Utility may decide not to seek recovery of certain costs. (See "Enforcement and Litigation Matters" in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations above.)

Changes in laws and regulations, changes in the political and regulatory environment, and fluctuating commodity prices also may have an adverse effect on the Utility's ability to timely recover its costs and earn its authorized rate of return. Although current law and regulatory mechanisms permit the Utility to pass through its costs to procure electricity and natural gas to customers in rates, a significant and sustained rise in commodity prices, caused by costs associated with new renewable energy resources and California's new cap-and-trade program and other factors, could create overall rate pressures that make it more difficult for the Utility to recover its costs. This pressure could increase as the Utility continues to collect authorized rates to support public purpose programs, such as energy efficiency programs, and low-income rate subsidies, and to fund customer incentive programs. Although the state legislature and the CPUC are addressing some of these issues through residential rate reform, it is uncertain when and how these issues will be resolved.

Further, PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreased new customer growth through bypass or municipalization of the Utility's facilities, an increase in the number of community choice aggregators who procure energy for residents of their communities, an increase in the number of customers who procure energy from alternate energy suppliers through "direct access," and the widespread deployment of self-generation and distributed generation technologies. As the number of bundled customers (i.e., those primarily residential customers who receive electricity and distribution service from the Utility) declines, the rates for remaining customers could increase. To relieve some of this upward rate pressure, it is possible that the CPUC could authorize lower revenues than the Utility requested or that the CPUC could disallow full cost recovery. In addition, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer net energy metering, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, also could put upward rate pressure on remaining customers. In early October 2014, the Utility filed its Bundled Procurement Plan that includes standards and criteria for the Utility's procurement activities for its bundled customers over the next ten years. The plan includes an alternative planning scenario which forecasts that by 2024, 36% of the total electric energy usage in the Utility's service territory will be provided by community choice aggregation, direct access, and distributed generation. As a result, the Utility would need to procure less electricity. The CPUC is not expected to issue a ruling on the Utility's Bundled Procurement Plan until early 2015. Also, a confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments.

If the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, increasing self-generation and net energy metering, and the growth of distributed generation and storage, PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows could be materially affected.

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

During the quarter ended September 30, 2014, PG&E Corporation made equity contributions totaling $125 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 September 30, 2014.

Issuer Purchases of Equity Securities

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

ITEM 5. OTHER INFORMATION

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

The Utility's earnings to fixed charges ratio for the nine months ended September 30, 2014 was 2.86. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the nine months ended September 30, 2014 was 2.83. 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 nine months ended September 30, 2014 was 2.84. 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-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 12348), Exhibit 4.1)
*10.1	Separation Agreement between PG&E Corporation and Greg Pruett dated August 8, 2014
*10.2	Separation Agreement between Pacific Gas and Electric Company and Thomas Bottorff dated September 17, 2014
*10.3	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and Steven Malnight dated February 22, 2012
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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
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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

*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.

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: October 28, 2014

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