PG&E Corp
Form 10-Q
October 28, 2015

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 30,2015

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

PG&E Corporation	Pacific Gas and Electric Company
77 Beale Street	77 Beale Street
P.O. Box 770000	P.O. Box 770000
San Francisco, California 94177	San Francisco, California94177

Address of principal executive offices, including zip code

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

Registrant's telephone number, including area code

Indicate by check mark whether each registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) have been subject to such filing requirements for the past 90 days. [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 20,2015:	
PG&E Corporation:	490,453,856
Pacific Gas and Electric Company:	264,374,809

PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY
FORM 10-Q

FOR THE QUARTERLY PERIOD ENDEDSEPTEMBER 30,2015

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GLOSSARY

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

2014 Form 10-K	PG&E Corporation's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2014
AFUDC	allowance for funds used during construction
ASU	Accounting Standards Update issued by the FASB (see below)
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DTSC	California Department of Toxic Substances Control
EPS	earnings per common share
EV	electric vehicle
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	U.S. Generally Accepted Accounting Principles
GRC	general rate case
GT&S	gas transmission and storage
IRS	Internal Revenue Service
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
ORA	Office of Ratepayer Advocates
PSEP	pipeline safety enhancement plan
Regional Board	California Regional Water Control Board, Lahontan Region
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
SB	State Senate Bill
TO	transmission owner
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)	2015	2014	2015	2014
Operating Revenues				
Electric	$3,868	$4,012	$10,344	$10,246
Natural gas	682	927	2,322	2,536
Total operating revenues	4,550	4,939	12,666	12,782
Operating Expenses				
Cost of electricity	1,681	1,782	3,958	4,341
Cost of natural gas	50	134	442	694
Operating and maintenance	1,621	1,287	5,028	3,914
Depreciation, amortization, and decommissioning	653	671	1,935	1,766
Total operating expenses	4,005	3,874	11,363	10,715
Operating Income	545	1,065	1,303	2,067
Interest income	2	2	6	7
Interest expense	(194)	(174)	(575)	(547)
Other income, net	24	36	100	98
Income Before Income Taxes	377	929	834	1,625
Income tax provision	67	115	84	310
Net Income	310	814	750	1,315
Preferred stock dividend requirement of subsidiary	3	3	10	10
Income Available for Common Shareholders	$307	$811	$740	$1,305
Weighted Average Common Shares Outstanding, Basic	486	472	481	466
Weighted Average Common Shares Outstanding, Diluted	489	474	484	468
Net Earnings Per Common Share, Basic	$0.63	$1.72	$1.54	$2.80
Net Earnings Per Common Share, Diluted	$0.63	$1.71	$1.53	$2.79
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		Nine Months Ended	
	September 30,		September 30,	
(in millions)	2015	2014	2015	2014
Net Income	$310	$814	$750	$1,315
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations				
(net of taxes of $0, $0, $0 and $0, at respective dates)	-	-	-	-
Net change in investments				
(net of taxes of $0, $13, $12 and $16, at respective dates)	-	(18)	(17)	(24)
Total other comprehensive income (loss)	-	(18)	(17)	(24)
Comprehensive Income	310	796	733	1,291
Preferred stock dividend requirement of subsidiary	3	3	10	10
Comprehensive Income Attributable to				
Common Shareholders	$307	$793	$723	$1,281

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
(in millions)	September 30, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	$154	$151
Restricted cash	287	298
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $57 and $66 at respective dates)	1,194	960
Accrued unbilled revenue	907	776
Regulatory balancing accounts	1,857	2,266
Other	303	377
Regulatory assets	475	444
Inventories:		
Gas stored underground and fuel oil	149	172
Materials and supplies	322	304
Income taxes receivable	156	198
Other	327	443
Total current assets	6,131	6,389
Property, Plant, and Equipment		
Electric	47,141	45,162
Gas	16,419	15,678
Construction work in progress	2,259	2,220
Other	2	2
Total property, plant, and equipment	65,821	63,062
Accumulated depreciation	(20,174)	(19,121)
Net property, plant, and equipment	45,647	43,941
Other Noncurrent Assets		
Regulatory assets	6,584	6,322
Nuclear decommissioning trusts	2,417	2,421
Income taxes receivable	97	91
Other	1,113	963
Total other noncurrent assets	10,211	9,797
TOTAL ASSETS	$61,989	$60,127

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

(in millions, except share amounts)	(Unaudited) Balance At September 30, 2015	December 31, 2014
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 881	$ 633
Accounts payable:		
Trade creditors	1,286	1,244
Regulatory balancing accounts	803	1,090
Other	435	476
Disputed claims and customer refunds	452	434
Interest payable	140	197
Other	2,111	1,846
Total current liabilities	6,108	5,920
Noncurrent Liabilities		
Long-term debt	15,545	15,050
Regulatory liabilities	6,294	6,290
Pension and other postretirement benefits	2,523	2,561
Asset retirement obligations	3,620	3,575
Deferred income taxes	8,773	8,513
Other	2,306	2,218
Total noncurrent liabilities	39,061	38,207
Commitments and Contingencies (Note 9)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares; 490,177,833 and 475,913,404 shares outstanding at respective dates	11,183	10,421
Reinvested earnings	5,391	5,316
Accumulated other comprehensive income (loss)	(6)	11
Total shareholders' equity	16,568	15,748
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	16,820	16,000
TOTAL LIABILITIES AND EQUITY	$ 61,989	$ 60,127

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)	2015	2014
Cash Flows from Operating Activities		
Net income	$750	$1,315
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,935	1,766
Allowance for equity funds used during construction	(80)	(72)
Deferred income taxes and tax credits, net	260	209
Disallowed capital expenditures	270	-
Other	247	258
Effect of changes in operating assets and liabilities:		
Accounts receivable	(322)	(177)
Inventories	5	(43)
Accounts payable	95	(57)
Income taxes receivable/payable	42	397
Other current assets and liabilities	(87)	358
Regulatory assets, liabilities, and balancing accounts, net	78	(994)
Other noncurrent assets and liabilities	(251)	(3)
Net cash provided by operating activities	2,942	2,957
Cash Flows from Investing Activities		
Capital expenditures	(3,662)	(3,564)
Decrease in restricted cash	11	2
Proceeds from sales and maturities of nuclear decommissioning trust investments	1,023	1,059
Purchases of nuclear decommissioning trust investments	(1,124)	(1,065)
Other	18	107
Net cash used in investing activities	(3,734)	(3,461)
Cash Flows from Financing Activities		
Repayments under revolving credit facilities	-	(260)
Net issuances (repayments) of commercial paper, net of discount of $2 and $1 at respective dates	545	(789)
Proceeds from issuance of short-term debt, net of issuance costs	-	300
Short-term debt matured	(300)	-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $14 and $6 at respective dates	486	1,819
Repayments of long-term debt	-	(889)
Common stock issued	689	743
Common stock dividends paid	(638)	(617)
Other	13	40
Net cash provided by financing activities	795	347

Net change in cash and cash equivalents	3	(157)
Cash and cash equivalents at January 1	151	296
Cash and cash equivalents at September 30	$154	$139

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Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(569)	$(516)
Income taxes, net	-	409
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	$223	$216
Capital expenditures financed through accounts payable	245	232
Noncash common stock issuances	15	16
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)	2015	2014	2015	2014
Operating Revenues				
Electric	$3,868	$4,012	$10,344	$10,244
Natural gas	682	927	2,322	2,536
Total operating revenues	4,550	4,939	12,666	12,780
Operating Expenses				
Cost of electricity	1,681	1,782	3,958	4,341
Cost of natural gas	50	134	442	694
Operating and maintenance	1,622	1,293	5,028	3,911
Depreciation, amortization, and decommissioning	653	671	1,935	1,765
Total operating expenses	4,006	3,880	11,363	10,711
Operating Income	544	1,059	1,303	2,069
Interest income	2	1	6	6
Interest expense	(191)	(171)	(567)	(535)
Other income, net	22	19	68	56
Income Before Income Taxes	377	908	810	1,596
Income tax provision	72	115	95	325
Net Income	305	793	715	1,271
Preferred stock dividend requirement	3	3	10	10
Income Available for Common Stock	$302	$790	$705	$1,261

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited) Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2015	2014	2015	2014
Net Income	$305	$793	$715	$1,271
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations				
(net of taxes of $0, $0, $0 and $0, at respective dates)	-	-	-	-
Total other comprehensive income (loss)	-	-	-	-
Comprehensive Income	$305	$793	$715	$1,271

See accompanying Notes to the Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	September 30, 2015	December 31, 2014
ASSETS		
Current Assets		
Cash and cash equivalents	$62	$55
Restricted cash	287	298
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $57 and $66 at respective dates)	1,194	960
Accrued unbilled revenue	907	776
Regulatory balancing accounts	1,857	2,266
Other	300	375
Regulatory assets	475	444
Inventories:		
Gas stored underground and fuel oil	149	172
Materials and supplies	322	304
Income taxes receivable	154	168
Other	327	409
Total current assets	6,034	6,227
Property, Plant, and Equipment		
Electric	47,141	45,162
Gas	16,419	15,678
Construction work in progress	2,259	2,220
Total property, plant, and equipment	65,819	63,060
Accumulated depreciation	(20,173)	(19,120)
Net property, plant, and equipment	45,646	43,940
Other Noncurrent Assets		
Regulatory assets	6,584	6,322
Nuclear decommissioning trusts	2,417	2,421
Income taxes receivable	97	91
Other	1,006	864
Total other noncurrent assets	10,104	9,698
TOTAL ASSETS	$61,784	$59,865

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
(in millions, except share amounts)	September 30, 2015	December 31, 2014
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 881	$ 633
Accounts payable:		
Trade creditors	1,286	1,243
Regulatory balancing accounts	803	1,090
Other	455	444
Disputed claims and customer refunds	452	434
Interest payable	139	195
Other	1,932	1,604
Total current liabilities	5,948	5,643
Noncurrent Liabilities		
Long-term debt	15,195	14,700
Regulatory liabilities	6,294	6,290
Pension and other postretirement benefits	2,435	2,477
Asset retirement obligations	3,620	3,575
Deferred income taxes	9,018	8,773
Other	2,264	2,178
Total noncurrent liabilities	38,826	37,993
Commitments and Contingencies (Note 9)		
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	7,127	6,514
Reinvested earnings	8,298	8,130
Accumulated other comprehensive income	5	5
Total shareholders' equity	17,010	16,229
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 61,784	$ 59,865

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Nine Months Ended September 30,			
(in millions)	2015		2014	
Cash Flows from Operating Activities				
Net income	$	715	$	1,271
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, amortization, and decommissioning		1,935		1,765
Allowance for equity funds used during construction		(80)		(72)
Deferred income taxes and tax credits, net		245		173
Disallowed capital expenditures		270		-
Other		200		212
Effect of changes in operating assets and liabilities:				
Accounts receivable		(321)		(174)
Inventories		5		(43)
Accounts payable		148		(3)
Income taxes receivable/payable		14		407
Other current assets and liabilities		(45)		366
Regulatory assets, liabilities, and balancing accounts, net		78		(994)
Other noncurrent assets and liabilities		(232)		6
Net cash provided by operating activities		2,932		2,914
Cash Flows from Investing Activities				
Capital expenditures		(3,662)		(3,564)
Decrease in restricted cash		11		2
Proceeds from sales and maturities of nuclear decommissioning				

trust investments		1,023		1,059
Purchases of nuclear decommissioning trust investments		(1,124)		(1,065)
Other		18		22
Net cash used in investing activities		(3,734)		(3,546)
Cash Flows from Financing Activities				
Net issuances (repayments) of commercial paper, net of discount of $2 and $1 at respective dates		545		(789)
Proceeds from issuance of short-term debt, net of issuance costs		-		300
Short-term debt matured		(300)		-
Proceeds from issuance of long-term debt, net of premium, discount, and issuance costs of $14 and $3 at respective dates		486		1,472
Repayments of long-term debt		-		(539)
Preferred stock dividends paid		(10)		(10)
Common stock dividends paid		(537)		(537)
Equity contribution from PG&E Corporation		605		705
Other		20		50
Net cash provided by financing activities		809		652
Net change in cash and cash equivalents		7		20
Cash and cash equivalents at January 1		55		65
Cash and cash equivalents at September 30	$	62	$	85

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Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(561)	$(500)
Income taxes, net	-	408
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$245	$232
Terminated capital leases	-	71

See accompanying Notes to the Condensed Consolidated Financial Statements.

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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.

On April 9, 2015, the CPUC approved final decisions in the three investigations that had been brought against the Utility relating to (1) the Utility's safety record-keeping for its natural gas transmission system, (2) the Utility's operation of its natural gas transmission pipeline system in or near locations of higher population density, and (3) the Utility's pipeline installation, integrity management, record-keeping and other operational practices, and other events or courses of conduct, that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. A decision was issued in each investigative proceeding to determine the violations that the Utility committed. The CPUC also approved a fourth decision (the "Penalty Decision") which imposes penalties on the Utility totaling $1.6 billion comprised of: (1) a $300 million fine paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. The Penalty Decision requires that at least $689 million of the $850 million be allocated to capital expenditures and that the Utility be precluded from including these capital costs in rate base. The remainder will be allocated to safety-related expenses. (See Note 9 below.)

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 other wholly owned and controlled subsidiaries. The Utility's Condensed Consolidated Financial Statements include the accounts of the Utility and its wholly owned and controlled subsidiaries. All intercompany transactions have been eliminated in consolidation. The Notes to the Condensed Consolidated Financial Statements apply to both PG&E Corporation and the Utility. 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, 2014 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in the 2014 Form 10-K. This quarterly report should be read in conjunction with the 2014 Form 10-K.

The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant 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 2014 Form 10-K.

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, 2015, 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, 2015, it did not consolidate any of them.

Pension and Other Postretirement Benefits

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan and cash balance plan. Both plans are included in "Pension Benefits" below. Post-retirement medical and life insurance plans are included in "Other Benefits" below.

The net periodic benefit costs reflected in PG&E Corporation's Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2015 and 2014 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended September 30,			
(in millions)	2015	2014	2015	2014
Service cost for benefits earned	$ 123	$ 92	$ 14	$ 12
Interest cost	168	175	18	19
Expected return on plan assets	(219)	(202)	(28)	(25)
Amortization of prior service cost	4	5	4	6
Amortization of net actuarial loss	1	1	1	1
Net periodic benefit cost	77	71	9	13
Regulatory account transfer (1)	8	13	-	-
Total	$ 85	$ 84	$ 9	$ 13

(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	

(in millions)	Nine Months Ended September 30, 2015	2014	2015	2014
Service cost for benefits earned	$ 360	$ 287	$ 41	$ 34
Interest cost	505	521	54	57
Expected return on plan assets	(655)	(605)	(84)	(77)
Amortization of prior service cost	11	15	14	17
Amortization of net actuarial loss	7	2	3	2
Net periodic benefit cost	228	220	28	33
Regulatory account transfer (1)	26	31	-	-
Total	$ 254	$ 251	$ 28	$ 33

(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.

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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	Total
	Three Months Ended September 30, 2015		
Beginning balance	$ (21)	$ 15	$ (6)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost			
(net of taxes of $1 and $2, respectively)	3	2	5
Amortization of net actuarial loss			
(net of taxes of $0 and $0, respectively)	1	1	2
Regulatory account transfer			
(net of taxes of $3 and $3, respectively)	(4)	(3)	(7)
Net current period other comprehensive loss	-	-	-
Ending balance	$ (21)	$ 15	$ (6)

(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, 2014			
Beginning balance	$(7)	$ 15	$ 36	$ 44
Other comprehensive income before reclassifications:				
Change in 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
Regulatory account transfer				
(net of taxes of $3, $4, and $0, respectively) (1)	(3)	(3)	-	(6)
Change in 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.)

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(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
	Nine Months Ended September 30, 2015			
Beginning balance	$(21)	$ 15	$ 17	$11
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost				
(net of taxes of $4, $6, and $0, respectively) (1)	7	8	-	15
Amortization of net actuarial loss				
(net of taxes of $3, $1, and $0, respectively) (1)	4	2	-	6
Regulatory account transfer				
(net of taxes of $7, $7, and $0, respectively) (1)	(11)	(10)	-	(21)
Change in investments				
(net of taxes of $0, $0, and $12, respectively)	-	-	(17)	(17)
Net current period other comprehensive loss	-	-	(17)	(17)
Ending balance	$(21)	$ 15	$ -	$(6)

(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:				
Change in 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
Regulatory account transfer				
(net of taxes of $7, $8, and $0, respectively) (1)	(10)	(11)	-	(21)
Change in 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.)

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.

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Accounting Standards Issued But Not Yet Adopted

Fair Value Measurement

In May 2015, the FASB issued ASU No. 2015-07, Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent), which standardizes reporting practices related to the fair value hierarchy for all investments for which fair value is measured using the net asset value per share. The ASU will be effective for fiscal years beginning after December 15, 2015. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their disclosures and will adopt this standard starting in the first quarter of 2016.

Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued ASU No. 2015-05, Intangibles – Goodwill and Other – Internal-Use Software (Subtopic 350-40): Customer's Accounting for Fees Paid in a Cloud Computing Arrangement, which adds guidance to help entities evaluate the accounting treatment for cloud computing arrangements. The ASU will be effective on January 1, 2016. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their consolidated financial statements and related disclosures and will adopt this standard starting in the first quarter of 2016.

Presentation of Debt Issuance Costs

In April 2015, the FASB issued ASU No. 2015-03, Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs, which amends existing presentation of debt issuance costs. PG&E Corporation and the Utility currently disclose debt issuance costs in current assets – other and noncurrent assets – other. The amendments in this ASU, effective on January 1, 2016, require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. PG&E Corporation and the Utility do not expect this reclassification to have a material impact on their consolidated financial statements. PG&E Corporation and the Utility will adopt this standard starting in the first quarter of 2016.

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which amends existing revenue recognition guidance. In August 2015, the FASB issued ASU No. 2015-14, Revenue from Contracts with

Customers (Topic 606): Deferral of the Effective Date, deferring the effective date of this amendment for public companies by one year to January 1, 2018, with early adoption permitted as of the original effective date of 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, 2015	December 31, 2014
Pension benefits	$2,304	$ 2,347
Deferred income taxes	2,771	2,390
Environmental compliance costs	705	717
Utility retained generation	423	456
Price risk management	143	127
Unamortized loss, net of gain, on reacquired debt	98	113
Electromechanical meters	18	70
Other	122	102
Total long-term regulatory assets	$6,584	$ 6,322

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Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

	Balance at	
	September 30,	December 31,
(in millions)	2015	2014
Cost of removal obligations	$4,509	$ 4,211
Recoveries in excess of asset retirement obligations	610	754
Public purpose programs	701	701
Other	474	624
Total long-term regulatory liabilities	$6,294	$ 6,290

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 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. Balancing accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

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

	Receivable Balance at	
	September 30,	December 31,
(in millions)	2015	2014
Electric distribution	$265	$ 344
Utility generation	24	261
Gas distribution	718	566
Energy procurement	390	608
Public purpose programs	136	109
Other	324	378
Total regulatory balancing accounts receivable	$1,857	$ 2,266

	Payable Balance at	
(in millions)	September 30, 2015	December 31, 2014
Energy procurement	$181	$ 188
Public purpose programs	173	154
Other	449	748
Total regulatory balancing accounts payable	$803	$ 1,090

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NOTE 4: DEBT

Revolving Credit Facilities and Commercial Paper Program

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving credit facilities and commercial paper programs at September 30, 2015:

(in millions)	Termination Date	Facility Limit		Letters of Credit Outstanding	Commercial Paper	Facility Availability
PG&E Corporation	April 2020	$ 300	(1)	$ -	$ -	$ 300
Utility	April 2020	3,000	(2)	34	881	2,085
Total revolving credit facilities		$ 3,300		$ 34	$ 881	$ 2,385

(1)Includes a $50 million sublimit for letters of credit and a $100 million commitment for "swingline" loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.

(2) Includes a $500 million sublimit for letters of credit and a $75 million commitment for swingline loans.

On April 27, 2015, PG&E Corporation and the Utility amended and restated their respective $300 million and $3.0 billion revolving credit facilities. The amendments and restatements extended the termination dates of the credit facilities from April 1, 2019 to April 27, 2020, reduced the amount of lender commitments to the letter of credit sublimits from $100 million to $50 million for PG&E Corporation's credit facility and from $1.0 billion to $500 million for the Utility's credit facility, and reduced the swingline commitment on the Utility's credit facility from $300 million to $75 million.

In July 2015, the Utility increased the commercial paper program limit from $1.75 billion to $2.5 billion. PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 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.

Issuances and Maturities

In June 2015, the Utility issued $400 million principal amount of 3.50% Senior Notes due June 15, 2025 and $100 million of 4.30% Senior Notes due March 15, 2045. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper. In addition, $300 million principal amount of the Utility's Floating Rate Senior Notes matured in May 2015.

Variable Rate Interest

At September 30, 2015, 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 were 0.01%. At September 30, 2015, the interest rates on the $309 million principal amount of pollution control bonds Series 2009 A-D and the related loan agreements were 0.01%.

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NOTE 5: EQUITY

PG&E Corporation’s and the Utility’s changes in equity for the nine months ended September 30, 2015were as follows:

(in millions)	PG&E Corporation Total Equity	Utility Total Shareholders' Equity
Balance at December 31, 2014	$ 16,000	$ 16,229
Comprehensive income	733	715
Equity contributions	-	605
Common stock issued	704	-
Share-based compensation	58	8
Common stock dividends declared	(665)	(537)
Preferred stock dividend requirement	-	(10)
Preferred stock dividend requirement of subsidiary	(10)	-
Balance at September 30, 2015	$ 16,820	$ 17,010

In February 2015, 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. In the first quarter of 2015, PG&E Corporation sold 1.4 million shares under this agreement for cash proceeds of $74 million, net of commissions paid of $1 million. No additional shares have been sold under the equity distribution agreement.

In August 2015, PG&E Corporation sold 6.8 million shares of its common stock in an underwritten public offeringfor cash proceeds of $352 million, net of fees.

PG&E Corporation also 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, 2015, 6.1 million shares were issued for cash proceeds of $263 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)	2015	2014	2015	2014
Income available for common shareholders	$307	$811	$740	$1,305
Weighted average common shares outstanding, basic	486	472	481	466
Add incremental shares from assumed conversions:				
Employee share-based compensation	3	2	3	2
Weighted average common share outstanding, diluted	489	474	484	468
Total earnings per common share, diluted	$0.63	$1.71	$1.53	$2.79

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

Use of Derivative Instruments

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities. Procurement costs are recovered through customer rates. The Utility uses both derivative and non-derivative contracts to manage volatility in customer rates due to fluctuating commodity prices. Derivatives include forward contracts, swaps, futures, options, and CRRs.

Derivatives are presented in the Utility's Condensed Consolidated Balance Sheets on a net basis in accordance with master netting arrangements for each counterparty. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Condensed Consolidated Balance Sheets. These instruments are not held for speculative purposes and are subject to certain regulatory requirements. 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 on the Condensed Consolidated Balance Sheets. 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 elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those 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. These items are not reflected in the Condensed Consolidated Balance Sheets at fair value. Eligible derivatives are accounted for under the accrual method of accounting.

Volume of Derivative Activity

The volumes of the Utility's outstanding derivatives were as follows:

		Contract Volume at	
Underlying Product	Instruments	September 30, 2015	December 31, 2014

Natural Gas (1) (MMBtus (2))	Forwards and Swaps	276,847,153	308,130,101
	Options	134,380,439	164,418,002
Electricity (Megawatt-hours)	Forwards and Swaps	4,884,523	5,346,787
	Congestion Revenue Rights (3)	186,018,832	224,124,341

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

(2) Million British Thermal Units.

(3)CRRs are financial instruments that enable the holders to manage variability in electric energy congestion charges due to transmission grid limitations.

Presentation of Derivative Instruments in the Financial Statements

At September 30, 2015, the Utility’s outstanding derivative balances were as follows:

	Commodity Risk			
	Gross Derivative			Total Derivative
(in millions)	Balance	Netting	Cash Collateral	Balance
Current assets – other	$63	$ (2)	$ 11	$ 72
Other noncurrent assets – other	130	(2)	-	128
Current liabilities – other	(84)	2	34	(48)
Noncurrent liabilities – other	(145)	2	24	(119)
Net commodity risk	$(36)	$ -	$ 69	$ 33

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At December 31, 2014, the Utility's outstanding derivative balances were as follows:

(in millions)	Commodity Risk Gross Derivative Balance	Netting	Cash Collateral	Total Derivative Balance
Current assets – other	$73	(4)	19	$ 88
Other noncurrent assets – other	178	(13)	-	165
Current liabilities – other	(78)	4	26	(48)
Noncurrent liabilities – other	(140)	13	9	(118)
Net commodity risk	$33	$ -	$ 54	$ 87

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)	2015	2014	2015	2014
Unrealized gain (loss) - regulatory assets and liabilities (1)	$(45)	$ (6)	$(69)	$79
Realized gain (loss) - cost of electricity (2)	1	(22)	4	(48)
Realized loss - cost of natural gas (2)	(3)	(4)	(8)	(7)
Net commodity risk	$(47)	$ (32)	$(73)	$24

(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.

Cash inflows and outflows associated with derivatives are included in operating cash flows on the Utility's Condensed Consolidated Statements of Cash Flows.

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, 2015, 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, 2015	December 31, 2014
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$ (2)	$ (47)
Collateral posting in the normal course of business related to these derivatives	-	44
Net position of derivative contracts/additional collateral posting requirements (1)	$ (2)	$ (3)

(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.

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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.

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

	Fair Value Measurements At September 30, 2015				
(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Money market investments	$92	$-	$-	$ -	$92
Nuclear decommissioning trusts					
Money market investments	21	-	-	-	21
Global equity securities	1,445	12	-	-	1,457
Fixed-income securities	710	523	-	-	1,233
Total nuclear decommissioning trusts (2)	2,176	535	-	-	2,711
Price risk management instruments (Note 7)					
Electricity	-	4	185	7	196
Gas	-	4	-	-	4
Total price risk management instruments	-	8	185	7	200
Rabbi trusts					
Fixed-income securities	-	45	-	-	45
Life insurance contracts	-	71	-	-	71
Total rabbi trusts	-	116	-	-	116
Long-term disability trust					
Money market investments	7	-	-	-	7
Global equity securities	-	18	-	-	18
Fixed-income securities	-	106	-	-	106
Total long-term disability trust	7	124	-	-	131
Total assets	$2,275	$783	$185	$ 7	$3,250
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$60	$3	$164	$ (62)	$165
Gas	-	2	-	-	2
Total liabilities	$60	$5	$164	$ (62)	$167

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

(2) Represents amount before deducting $294 million, primarily related to deferred taxes on appreciation of investment value.

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(in millions)	Fair Value Measurements At December 31, 2014 Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Money market investments	$94	$-	$-	$ -	$94
Nuclear decommissioning trusts					
Money market investments	17	-	-	-	17
Global equity securities	1,585	13	-	-	1,598
Fixed-income securities	741	389	-	-	1,130
Total nuclear decommissioning trusts (2)	2,343	402	-	-	2,745
Price risk management instruments (Note 9 in the 2014 Form 10-K)					
Electricity	-	17	232	2	251
Gas	1	1	-	-	2
Total price risk management instruments	1	18	232	2	253
Rabbi trusts					
Fixed-income securities	-	42	-	-	42
Life insurance contracts	-	72	-	-	72
Total rabbi trusts	-	114	-	-	114
Long-term disability trust					
Money market investments	7	-	-	-	7
Global equity securities	-	25	-	-	25
Fixed-income securities	-	128	-	-	128
Total long-term disability trust	7	153	-	-	160
Other investments	33	-	-	-	33
Total assets	$2,478	$687	$232	$ 2	$3,399
Liabilities:					
Price risk management instruments (Note 9 in the 2014 Form 10-K)					
Electricity	$47	$5	$163	$ (52)	$163
Gas	-	3	-	-	3
Total liabilities	$47	$8	$163	$ (52)	$166

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.

(2) Represents amount before deducting $324 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, 2015 and 2014.

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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 California Independent System Operator-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 California Independent System Operator 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 At September 30, 2015		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	Input	Range (1)
Congestion revenue rights	$ 185	$ 51	Market approach	CRR auction prices	$ (15.97) - 8.17
Power purchase agreements	$ -	$ 113	Discounted cash flow	Forward prices	$ 17.64 - 38.80

(1) Represents price per megawatt-hour

(in millions)	Fair Value at At December 31, 2014		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	Input	Range (1)
Congestion revenue rights	$ 232	$ 63	Market approach	CRR auction prices	$ (15.97) - 8.17
Power purchase agreements	$ -	$ 100	Discounted cash flow	Forward prices	$ 16.04 - 56.21

(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, 2015 and 2014:

	Price Risk Management Instruments	
(in millions)	2015	2014
Asset (liability) balance as of July 1	$ 48	$ (11)
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(27)	(9)
Asset (liability) balance as of September 30	$ 21	$ (20)

(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 2015	2014
Asset (liability) balance as of January 1	$ 69	$ (30)
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(48)	10
Asset (liability) balance as of September 30	$ 21	$ (20)

(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, 2015 and December 31, 2014, 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, 2015 and December 31, 2014.

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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, 2015		At December 31, 2014	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
PG&E Corporation	$350	$354	$350	$352
Utility	14,273	15,858	13,778	15,851

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, 2015				
Nuclear decommissioning trusts				
Money market investments	$ 21	$-	$-	$21
Global equity securities	510	963	(16)	1,457
Fixed-income securities	1,168	70	(5)	1,233
Total (1)	$ 1,699	$1,033	$(21)	$2,711
As of December 31, 2014				
Nuclear decommissioning trusts				
Money market investments	$ 17	$-	$-	$17
Global equity securities	520	1,087	(9)	1,598
Fixed-income securities	1,059	75	(4)	1,130
Total nuclear decommissioning trusts (1)	1,596	1,162	(13)	2,745
Other investments	5	28	-	33
Total	$ 1,601	$1,190	$(13)	$2,778

(1) Represents amounts before deducting $294 million and $324 million at September 30, 2015 and December 31, 2014, respectively, primarily related to deferred taxes on appreciation of investment value.

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

As of

(in millions)	September 30, 2015
Less than 1 year	$ 21
1–5 years	465
5–10 years	290
More than 10 years	457
Total maturities of debt securities	$ 1,233

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
(in millions)				
Proceeds from sales and maturities of nuclear decommissioning trust investments	$244	$182	$ 1,023	$1,059
Gross realized gains on securities held as available-for-sale	3	30	50	114
Gross realized losses on securities held as available-for-sale	(12)	-	(25)	(3)

NOTE 9: CONTINGENCIES AND COMMITMENTS

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

Enforcement and Litigation Matters

CPUC Matters

Improper CPUC Communications

In September 2014, the Utility notified the CPUC of ex parte communications between the Utility and the CPUC regarding the 2015 GT&S rate case. Ex parte communications include any communication between a decision maker and an interested person concerning substantive issues in certain identified categories of formal proceedings before the CPUC. In November 2014, the CPUC imposed a fine of $1.05 million on the Utility for these communications. In addition, the CPUC may disallow the Utility from recovering up to the entire amount of the revenue increase that may be authorized in the pending GT&S rate case and that otherwise would have been collected from ratepayers over a five-month period. The CPUC will determine the amount of this disallowance when it issues its decision to authorize the Utility's GT&S revenue requirements, which is expected to be issued in 2016.

In October and December 2014, the Utility also notified the CPUC of additional email communications between the Utility and the CPUC regarding various matters (not limited to the GT&S rate case) that the Utility believes may constitute or describe ex parte communications. The Utility also notified the CPUC of an additional potential ex parte communication made in the 2011 General Rate Case to supplement a notification that the Utility voluntarily provided on October 6, 2014. Additionally, on May 21, 2015, the Utility filed various documents (including copies of internal email correspondence) with the CPUC to complete its response to orders issued by CPUC administrative law judges regarding potential ex parte communications between the Utility and CPUC personnel. For these additional communications, the Utility believes it is probable that CPUC enforcement action will be taken. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining the final penalties.

In the Penalty Decision (further described below), the CPUC stated that it will begin a new investigation to examine allegations by the City of San Bruno that communications between the Utility's employees and CPUC personnel violated the CPUC's rules relating to ex parte communications. The Utility believes that the communications cited by San Bruno are not prohibited ex parte communications. If the CPUC determines that the communications constitute ex parte violations, it is reasonably possible that the CPUC will impose penalties or other remedies, but the Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion and the number of factors that can be considered in determining the final penalties.

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

CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping

On November 20, 2014, the CPUC began an investigation into whether the Utility violated applicable laws pertaining to record-keeping practices with respect to maintaining safe operation of its natural gas distribution service and facilities. The order also requires the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. In particular, the order cites the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014, for which the CPUC has previously imposed a penalty of $10.85 million.

On September 30, 2015, the SED submitted its supplemental testimony, which included incidents allegedly related to record-keeping that had not been identified in the initial order, and also asserted violations related to the Utility's pre-excavation location and marking practices, causal evaluation practices, and compliance with regulations governing pressure validation for certain distribution facilities. Testimony from intervenors was submitted in October 2015. The Utility's response is due on November 12, 2015, followed by rebuttal testimony in December 2015. Hearings are scheduled for January 2016.

The CPUC can impose penalties of up to $50,000 per day, per violation, for violations that occurred after January 1, 2012. (The statutory maximum penalty for violations that occurred before January 1, 2012 is $20,000 per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised this wide discretion in determining penalties.

PG&E Corporation and the Utility believe it is reasonably possible that the CPUC will impose penalties on the Utility or that the Utility will incur unrecoverable costs to implement operational remedies. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the CPUC's wide discretion (discussed above) and the number of factors that can be considered in determining penalties and given the fact that the extent of any alleged violations is currently unknown.

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 address a self-reported violation whereby the Utility did not properly 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. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the SED's wide discretion and the number of factors that can be considered in determining penalties.

Potential Safety Citations

The SED periodically audits utility operating practices and conducts investigations of potential violations of laws and regulations applicable to the safety of the California utilities' electric and natural gas facilities and operations. The CPUC has delegated authority to the SED to issue citations and impose fines for violations identified through audits, investigations, or self-reports. Although the SED can consider the discretionary factors discussed above (see "CPUC Investigation Regarding Natural Gas Distribution Facilities Record-Keeping" above) in determining the number of violations and whether to impose fines, the SED is required to impose the maximum statutory penalty of $50,000 for each separate violation and has the discretion to impose daily fines for continuing violations.

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The SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The Utility believes it is probable that the SED will impose fines or take other enforcement action based on some of the Utility’s self-reported non-compliance with laws and regulations or based on allegations of non-compliance with such laws and regulations that are contained in some of the SED’s audits. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred for fines imposed by the SED with respect to these matters given the wide discretion the SED has in determining whether to bring enforcement action and the number of factors that can be considered in determining the amount of fines.

Federal Matters

Federal Criminal Indictment

On July 29, 2014, a federal grand jury for the Northern District of California returned a 28-count superseding criminal indictment against the Utility in federal district court that succeeded the original indictment that was returned on April 1, 2014. The superseding indictment charges 27 felony counts alleging 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 into the cause 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 alternative fine would be approximately $1.13 billion. The trial is scheduled to begin March 8, 2016.

The Utility entered a plea of not guilty. The Utility believes that criminal charges and the alternative fine allegations 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. The Utility has filed several motions requesting that the court dismiss many of the counts based on various legal arguments. The court has heard oral argument on all the motions and the Utility is waiting for the court’s decisions. 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 Federal Matters

The Utility was informed that the U.S. Attorney’s Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. (For more information refer to Note 14 of the Notes to the Consolidated

Financial Statements appearing under Item 8 in the 2014 Form 10-K). The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case discussed above. It is uncertain whether any additional charges will be brought against the Utility.

Capital Expenditures Relating to Pipeline Safety Enhancement Plan

At September 30, 2015, approximately $657 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 to the statement of income in future periods to the extent total forecasted PSEP-related capital costs are higher than currently expected.

Penalty Decision Related to the CPUC's Investigative Enforcement Proceedings Related to Natural Gas Transmission

The Penalty Decision (see Note 1 above) imposes penalties on the Utility totaling $1.6 billion comprised of: (1) a $300 million fine to be paid to the State General Fund, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund future pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million. In August 2015, the Utility paid the $300 million fine. At September 30, 2015, the Condensed Consolidated Balance Sheets include $400 million in current regulatory liabilities for the one-time bill credit that will be provided to the Utility's natural gas customers in 2016.

The Penalty Decision requires that at least $689 million of the $850 million disallowance be allocated to capital expenditures, and that the Utility be precluded from including these capital costs in rate base. The CPUC will determine which safety projects and programs will be funded by shareholders in the Utility's pending 2015 GT&S rate case. If the $850 million is not exhausted by designated safety-related projects and programs in the GT&S proceeding, the CPUC will identify additional projects in future proceedings to ensure that the full $850 million is spent. The CPUC is expected to issue a final decision in the Utility's 2015 GT&S rate case in 2016 to identify safety-related projects and programs that will be subject to the disallowance. It is uncertain how the CPUC will identify the costs that are counted toward the $850 million shareholder-funded obligation. If the Utility's actual costs exceed costs that the CPUC counts towards the $850 million maximum, the Utility would record additional charges if such costs are not otherwise authorized by the CPUC. As a result, the total shareholder-funded obligation could exceed $850 million.

For the three months and nine months ended September 30, 2015, the Utility recorded additional charges in operating and maintenance expenses in the Consolidated Statements of Income of $142 million and $770 million, respectively, as a result of the Penalty Decision. The cumulative charges at September 30, 2015, and the additional future charges to reach the $1.6 billion total are shown in the following table:

(in millions)	Nine Months Ended September 30, 2015	Cumulative Charges September 30, 2015	Future Charges and Costs	Total Amount
Fine payable to the state (1)	$100	$ 300	$ -	$ 300
Customer bill credit	400	400	-	400
Charge for disallowed capital (2)	270	270	419	689
Disallowed revenue for pipeline safety expenses (3)	-	-	161	161
CPUC estimated cost of other remedies (4)	-	20	30	50
Total Penalty Decision fines and remedies	$770	$ 990	$ 610	$ 1,600

(1)In March 2015, the Utility increased its accrual from $200 million at December 31, 2014 to $300 million.

(2)The Penalty Decision prohibits the Utility from recovering certain expenses and capital spending associated with pipeline safety-related projects and programs that the CPUC will identify in the final decision to be issued in the Utility's 2015 GT&S rate case. The Utility estimates that approximately $142 million and $270 million of capital spending (which include less than $1 million for remedy related capital costs)in the three months and nine months ended September 30, 2015, respectively, are probable of disallowance, subject to adjustment based on the final 2015 GT&S rate case decision.

(3)These costs are being expensed as incurred. Future GT&S revenues will be reduced for these unrecovered expenses.

(4)In the Penalty Decision, the CPUC estimated that the Utility would incur $50 million to comply with the remedies specified in the Penalty Decision, including approximately $30 million for the cost of future audits to be conducted by the SED. The amounts shown in the table above represent these estimated amounts and do not reflect the Utility's remedy-related costs already incurred nor the Utility's estimated future remedy-related costs. The Utility has submitted testimony in its 2017 GRC request to remove additionalremedy-related costs of approximately $61 million. The Utility could incur remedy-related costs that are higher than current estimates.

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Other Legal and Regulatory Contingencies

Rehearing of CPUC Decisions Approving Energy Efficiency Incentive Awards

On September 17, 2015, the CPUC issued an order granting TURN's and the ORA's long-standing applications for rehearing of the CPUC decisions that awarded energy efficiency incentive payments to the California investor-owned utilities for the 2006-2008 energy efficiency program cycle. Under the ratemaking mechanism applicable to the 2006-2008 program cycle, the maximum amount of incentives that the Utility could have earned (or the maximum amount that the Utility could have been required to reimburse customers) over the 2006-2008 program cycle was $180 million. The Utility was awarded a total of $104 million for the 2006-2008 program cycle. In the re-opened energy efficiency proceeding, the CPUC will evaluate whether incentives awarded to the California investor-owned utilities were just and reasonable, and whether any refunds are due. It is uncertain when the CPUC will issue a decision and whether the Utility will be required to refund amounts or incur other obligations related to the 2006-2008 program cycle. PG&E Corporation and the Utility believe it is reasonably possible that the Utility will be required to refund amounts or incur other obligations related to this matter, but they are unable to reasonably estimate the amount of such refunds or other obligations.

Investigation of the Butte Fire

In September 2015, a wildfire (known as the "Butte Fire") ignited and spread in Amador and Calaveras Counties in Northern California. The California Department of Forestry and Fire Protection ("Cal Fire") is investigating the source of the fire including whether a live tree may have contacted apower line owned and operated by the Utility, in the vicinity of the ignition point. The Utility also is conducting an investigation. Cal Fire has reported that as a result of the fire there were two deaths and 965 structures, including 571 houses, were damaged or destroyed.

Although the cause of the fire has not yet been determined, PG&E Corporation and the Utility believe that it is reasonably possible that the Utility will incur a material amount of losses associated with third-party claims for property damage, fire suppression costs, personal injury, or other claims. PG&E Corporation and the Utility are unable to reasonably estimate the amount of possible losses (or range of amounts) given the preliminary stages of the investigation into the cause of the fire and uncertainty about the extent and value of real and personal property damaged by the fire which spread over 70,000 acres much of which is remote and rugged terrain. The Utility has insurance coverage for these types of claims. If the amount of insurance is insufficient to cover the Utility's liability resulting from the Butte fire, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition or results of operations could be materially affected.

Other Contingencies

Accruals for other legal and regulatory contingencies (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters" and "Other Legal and Regulatory Contingencies") totaled $61 million at September 30, 2015, and $55 million at December 31, 2014. 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, 2015	December 31, 2014
Topock natural gas compressor station (1)	$296	$ 291
Hinkley natural gas compressor station (1)	136	158
Former manufactured gas plant sites owned by the Utility or third parties	267	257
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites	153	150
Fossil fuel-fired generation facilities and sites	94	98
Total environmental remediation liability	$946	$ 954

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

At September 30, 2015, the Utility expected to recover $678 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC. Some of the Utility's environmental remediation liability, such as the environmental remediation costs associated with the Hinkley site discussed below, will not be recovered in rates.

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 also is required to take measures to abate the effects of the contamination on the environment.

Hinkley Site

The Utility has been implementing interim remediation measures at the Hinkley site to reduce the mass of the chromium plume and to monitor and control movement of the plume. The Utility's remediation and abatement efforts at the Hinkley site are overseen by the Regional Board. On October 16, 2015, the Regional Board issued a revised draft clean-up and abatement order, updating previous versions of the draft order released in September 2015 and January 2015. The updated draft order proposes that the Utility continue and improve its remediation efforts; defines the boundaries of the chromium plume, and take other action. The draft order also proposes to set plume capture requirements, proposes deadlines for the Utility to meet interim cleanup targets, and proposes to establish a monitoring and reporting program. After a public comment period, the Regional Board is expected to consider adoption of a final clean-up and abatement order at its November 2015 meeting.

The Utility’s environmental remediation liability at September 30, 2015 reflects the Utility’s best estimate of probable future costs associated with the continuation of interim remediation measures and the anticipated final clean-up and abatement order. 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 overseen by the DTSC and the U.S. Department of the Interior. While the Utility has been working with these agencies to develop a final remediation plan, the Utility has been employing various 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. In September 2014, the Utility submitted its near-final remediation plan to the agencies for approval. The Utility's plan proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. The DTSC is conducting an additional environmental review of the proposed plan, and the Utility anticipates that the DTSC's draft environmental impact report will be issued for public comment in July 2016. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in December 2016. After the Utility modifies its plan in response to the final report, the Utility plans to seek approval to begin construction of the new in-situ treatment system in early 2017.

The Utility's environmental remediation liability at September 30, 2015 reflects its best estimate of probable future costs associated with its anticipated final remediation plan. Future costs will depend on many factors, including the scope and timing of required remediation work. 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.

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. 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.

At December 31, 2014, the Consolidated Balance Sheets reflected $434 million in net claims, within Disputed claims and customer refunds, and $291 million of cash in escrow for payment of the remaining net disputed claims, within Restricted cash. There were no significant changes to these balances during the nine months ended September 30, 2015.

Tax Matters

The IRS is currently auditing several items in the 2011 to 2014 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 transmission and distribution businesses. PG&E Corporation and the Utility expect that the IRS will complete its audit of the 2011 and 2012 deductible repair costs for the electric transmission and distribution businesses in 2015. The IRS also is expected to issue guidance in late 2015 or 2016 that clarifies 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 outstanding audits related to the 2011 and 2012 tax returns. As of September 30, 2015, it is reasonably possible that unrecognized tax benefits will decrease by approximately $380 million within the next 12 months most of which would not impact net income.

There were no other significant developments to tax matters during the nine months ended September 30,2015. (Refer to Note 8 of the Notes to the Consolidated Financial Statements in Item 8 of the 2014 Form 10-K.)

Purchase 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. At December 31, 2014 the Utility hadundiscounted future expected obligations of approximately $53.3 billion. (See Note 14 of the Notes to the Consolidated Financial Statements in Item 8 of the 2014 Form 10-K.) During the nine months ended September 30, 2015, the Utility entered into several renewable energy and other power purchase agreements that were approved by the CPUC and completed major milestones with respect to construction, resulting in additional commitments of approximately $780 million over the next 25 years.

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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 2014 Form 10-K.

Summary of Changes in Net Income and Earnings per Share

The following table is a summary reconciliation of the key changes, after-tax, in PG&E Corporation's income available for common shareholders and EPS (as well as earnings from operations and EPS on an earnings from operations basis) compared to the same period in the prior year (see "Results of Operations" below). "Earnings from operations" is a non-GAAP financial measure and is calculated as income available for common shareholders less items impacting comparability. "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short- and long-term operating plans, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance. Earnings from operations are not a substitute or alternative for GAAP measures such as income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

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(in millions, except per share amounts)	Three Months Ended September 30, Earnings	EPS (Diluted)	Nine Months Ended September 30, Earnings	EPS (Diluted)
Income Available for Common Shareholders - 2014	$ 811	$ 1.71	$ 1,305	$ 2.79
Natural gas matters (1)	13	0.03	94	0.20
Environmental-related costs (2)	(4)	(0.01)	(4)	(0.01)
Earnings from Operations - 2014 (3)	$ 820	$ 1.73	$ 1,395	$ 2.98
Growth in rate base earnings	26	0.05	79	0.16
Nuclear refueling outage	-	-	26	0.05
2014 GRC cost recovery (4)	(228)	(0.47)	-	-
Timing of 2015 GT&S cost recovery (5)	(78)	(0.16)	(159)	(0.33)
Regulatory and legal matters (6)	(24)	(0.05)	(18)	(0.04)
Gain on disposition of SolarCity stock (7)	(14)	(0.03)	(13)	(0.03)
Timing of taxes (8)	(45)	(0.09)	(7)	(0.01)
Increase in shares outstanding	-	(0.05)	-	(0.10)
Miscellaneous	(45)	(0.09)	(31)	(0.05)
Earnings from Operations - 2015 (3)	$ 412	$ 0.84	$ 1,272	$ 2.63
Insurance recoveries (9)	6	0.01	29	0.06
Fines and penalties (10)	(84)	(0.16)	(497)	(1.03)
Pipeline-related expenses (11)	(19)	(0.04)	(38)	(0.08)
Legal and regulatory related expenses (11)	(8)	(0.02)	(26)	(0.05)
Income Available for Common Shareholders - 2015	$ 307	$ 0.63	$ 740	$ 1.53

(1) In 2014, natural gas matters included pipeline-related costs to perform work under the PSEP and other activities associated with safety improvements to the Utility’s natural gas system, as well as legal and other costs related to natural gas matters. Natural gas matters also included charges recorded related to fines, third party liability claims, and insurance recoveries in 2014.

(2) The Utility reduced its accrual related to the Hinkley whole house water program in the third quarter of 2014.

(3) “Earnings from operations” is not calculated in accordance with GAAP and excludes the items impacting comparability shown in Notes (1) and (2) above and Notes (9), (10), and (11) below.

(4)Represents the increase in base revenues authorized by the CPUC in the 2014 GRC decision, as well as the impact of flow-through ratemaking treatment for federal tax deductions for repairs, for the first two quarters of 2014. In 2014, the increase in base revenue and the impact of flow-through repairs deductions was not recognized until the quarter ended September 30, 2014, when the 2014 GRC decision was issued. Alsoincludes 2014 GRC related items included in Miscellaneous in previous quarters.

(5)Represents expenses during the three and nine months ended September 30, 2015 as compared to the same periods in 2014, with no corresponding increase in revenue. The Utility has requested the CPUC to authorize an increase to its revenue requirements for 2015, 2016, and 2017 in its 2015 GT&S rate case. Based on the procedural schedule, it is unlikely that the Utility will be able to recognize a revenue increase from a final 2015 GT&S rate case decision until 2016.

(6)Primarily reflects incentive awards received in 2014. Also includes legal costs included in Miscellaneous in previous quarters.

(7)Represents the gain recognized during the three months ended September 30, 2014 as compared to the three months ended September 30, 2015 during which no comparable gain was recognized.

(8)Represents the timing of taxes reportable in quarterly financial statements.

(9)Represents insurance recoveries of $10 million and $49 million, pre-tax, for third party claims and associated legal costs related to the San Bruno accident the Utility received during the three and nine months ended September 30, 2015, respectively. The Utility has received a cumulative total of $515 million through insurance related to $558 million of third-party claims and $92 million of legal costs incurred. No further insurance recoveries related to these claims and costs are expected.

(10)Represents the impact of the Penalty Decision (see Note 9 of the Notes to the Condensed Consolidated Financial Statements for before-tax amounts).

(11) In 2015, pipeline-related expenses include costs incurred to identify and remove encroachments from transmission pipeline rights of way and to perform remaining work under the Utility's PSEP. Legal and regulatory related expenses include various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

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:

- Penalties, Fines and Remedial Costs. Future financial results will be impacted by the timing and amount of disallowed costs the Utility incurs for designated pipeline safety-related projects and programs and to implement remedial measures, as required by the Penalty Decision. The Utility also could be required to pay fines associated with pending federal criminal charges. 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. The Utility also could be required to pay fines, or incur other unrecoverable costs, associated with the CPUC's pending investigation of the Utility's natural gas distribution record-keeping practices, enforcement action that may be taken with respect to ex parte communications or other improper communications between the Utility and the CPUC, or other enforcement matters. (See "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

- The Timing and Outcome of Ratemaking Proceedings. In the 2015 GT&S rate case, the Utility has requested that the CPUC authorize an increase in the Utility's revenue requirements for gas transmission and storage operations beginning on January 1, 2015, with additional increases in 2016 and 2017. Any revenue requirement increase would be retroactive to January 1, 2015. Based on the scoping ruling and procedural schedule that was issued on June 11, 2015, the CPUC's initial decision to authorize revenue requirements is not likely to be issued before December 31, 2015. If the Utility does not recognize any increase in 2015, the authorized revenue increase would be recorded in 2016. (See "Ratemaking Proceedings–2015 Gas Transmission and Storage Rate Case" below for more information.) In September 2015, the Utility filed its 2017 GRC application to request that the CPUC authorize revenue requirements for the Utility's electric generation business and its electric and natural gas distribution business for 2017 through 2019. (See "Ratemaking Proceedings–2017 General Rate Case" below for more information.) Also, the CPUC recently granted applications for rehearing of CPUC decisions issued in 2008, 2009, and 2010 that awarded a total of $104 million of incentive revenues to the Utility based on implementation of customer energy efficiency programs. It is uncertain whether the Utility would be required to refund any of the incentive revenues or incur other expense related to the final resolution of the re-opened proceedings. In addition, the Utility has one transmission owner rate case pending at the FERC (See "Ratemaking Proceedings – FERC TO Rate Cases" below). The outcome of ratemaking proceedings can be affected by many factors, including the level of opposition by intervening parties, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.

- The Ability of the Utility to Control Operating Costs and Capital Expenditures. Whether the Utility is able to earn its authorized rate of return could be materially affected if the Utility's actual costs differ from the amounts that have been authorized in the final 2014 GRC decision and that may be authorized in the 2015 GT&S rate case and future rate case decisions. In addition to incurring shareholder-funded costs and costs associated with remedial measures required by the Penalty Decision, the Utility forecasts that in 2015 it will incur unrecovered pipeline-related expenses ranging from $100 million to $125 million, which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. Actual costs could be higher. The ultimate amount of unrecovered costsalso could be affected by how the CPUC determines which costs are included in determining whether the $850 million shareholder-funded obligation under the Penalty Decision has been met, and the outcome of pending and future investigations and enforcement matters. (See "Enforcement and Litigation Matters" below.) The Utility's ability to recover costs in the future also could be affected by decreases in customer demand driven by legislative and regulatory initiatives relating to distributed generation resources, renewable energy requirements, and changes in the electric rate structure.

- 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, 2015, PG&E Corporation issued $689 million of common stock and made equity contributions to the Utility of $605 million. PG&E Corporation forecasts that it will continue issuing a material amount of equity in 2016 and future years to support the Utility's capital expenditures. PG&E Corporation will issue additional equity to fund the Utility's unrecoverable pipeline-related expenses (including charges incurred under the Penalty Decision) and to pay fines and penalties that may be required by the final outcomes of pending enforcement matters. These additional equity issuances would have a further 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 the outcome of the matters discussed in "Enforcement and Litigation Matters" below, changes in their respective credit ratings, general economic and market conditions, and other factors.

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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 "Item 1A. Risk Factors"in the 2014 Form 10-K and in Part II below under "Item 1A. Risk Factors." 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, 2015 and 2014:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2015	2014	2015	2014
Consolidated Total	$ 307	$ 811	$ 740	$ 1,305
PG&E Corporation	5	21	35	44
Utility	$ 302	$ 790	$ 705	$ 1,261

PG&E Corporation's net income primarily consists of interest expense on long-term debt, income taxes, and other income from investments. Results include approximately $30 million and $45 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation recognized in the nine months ended September 30, 2015 and 2014, respectively.

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, 2015 and 2014. 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.

The Utility's operating results for the three and nine months ended September 30, 2015 reflect charges associated with the impact of the Penalty Decision. (See "Utility Revenues and Costs that Impacted Earnings" below.)

(in millions)	Three Months Ended September 30, 2015 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	Three Months Ended September 30, 2014 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$1,907	$ 1,961	$3,868	$1,979	$ 2,033	$4,012
Natural gas operating revenues	516	166	682	643	284	927
Total operating revenues	2,423	2,127	4,550	2,622	2,317	4,939
Cost of electricity	-	1,681	1,681	-	1,782	1,782
Cost of natural gas	-	50	50	-	134	134
Operating and maintenance	1,226	396	1,622	892	401	1,293
Depreciation, amortization, and decommissioning	653	-	653	671	-	671
Total operating expenses	1,879	2,127	4,006	1,563	2,317	3,880
Operating income	544	-	544	1,059	-	1,059
Interest income (1)			2			1
Interest expense (1)			(191)			(171)
Other income, net (1)			22			19
Income before income taxes			377			908
Income tax provision (1)			72			115
Net income			305			793
Preferred stock dividend requirement (1)			3			3
Income Available for Common Stock			$302			$790

(1) These items impacted earnings for the three months ended September 30, 2015 and 2014.

(in millions)	Nine Months Ended September 30, 2015 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	Nine Months Ended September 30, 2014 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$5,569	$ 4,775	$10,344	$5,200	$ 5,044	$10,244
Natural gas operating revenues	1,547	775	2,322	1,569	967	2,536
Total operating revenues	7,116	5,550	12,666	6,769	6,011	12,780
Cost of electricity	-	3,958	3,958	-	4,341	4,341
Cost of natural gas	-	442	442	-	694	694
Operating and maintenance	3,878	1,150	5,028	2,935	976	3,911
Depreciation, amortization, and decommissioning	1,935	-	1,935	1,765	-	1,765
Total operating expenses	5,813	5,550	11,363	4,700	6,011	10,711
Operating income	1,303	-	1,303	2,069	-	2,069
Interest income (1)			6			6
Interest expense (1)			(567)			(535)
Other income, net (1)			68			56
Income before income taxes			810			1,596
Income tax provision (1)			95			325

Net income	715	1,271
Preferred stock dividend requirement (1)	10	10
Income Available for Common Stock	$705	$1,261

(1) These items impacted earnings for the nine months ended September 30, 2015 and 2014.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for the threeand nine months ended September 30, 2015 and 2014, focusing on revenues and expenses that impacted earnings for these periods.

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Operating Revenues

The Utility's electric and natural gas operating revenues that impacted earnings decreased by $199 million, or 8%,in the three months ended September 30, 2015, compared to the same period in 2014 primarily due to the timing of the 2014 GRC decision that was issued in August 2014. Revenue increases of approximately $305 million pertaining to the six months ended June 30, 2014 were not recognized until the third quarter of 2014. Additionally, operating revenues decreased in the three months ended September 30, 2015 due to the absence of approximately $35 million of revenues the CPUC authorized the Utility to collect for recovery of certain PSEP-related costs during the same period in 2014. These decreases were offset by an increase in base revenues of approximately $150 million as authorized by the CPUC in the 2014 GRC and by the FERC in the TO rate case.

The Utility's electric and natural gas operating revenues that impacted earnings increased by $347 million, or 5%, in the ninemonths endedSeptember 30,2015, compared to the same period in 2014. The increase was primarily a result of approximately $410 million of additional base revenues as authorized by the CPUC in the 2014 GRC decision and the FERC in the TO rate case. This increase was partially offset by the absence of approximately $100 million of revenues the CPUC authorized the Utility to collect for recovery of certain PSEP-related costs during the same period in 2014.

Recovery of PSEP-related costs incurred during 2015 will depend upon the timing and outcome of the GT&S rate case. The Utility has requested the CPUC authorize an increase to its revenue requirements for 2015, 2016, and 2017 in its GT&S rate case. Based on the procedural schedule, it is unlikely that the Utility will be able to recognize an increase in its GT&S revenue before 2016. (See "Ratemaking Proceedings" below.)

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased by $334million, or 37%, in the three months ended September 30, 2015 compared to the same period in 2014primarily due to $142 millionin charges associated with the Penalty Decision (see Note 9 of the Notes to the Condensed Consolidated Financial Statements). Additionally, the Utility received $76 million fewer insurance recoveries during the three months ended September 30, 2015 compared to the same period in 2014.

The Utility's operating and maintenance expenses that impacted earnings increased by $943 million, or 32%, in the nine months ended September 30,2015 compared to the same periods in 2014 primarily due to $770 million in charges associated with the Penalty Decision (see Note 9 of the Notes to the Condensed Consolidated Financial Statements). Additionally, the Utility received $37 million fewer insurance recoveriesfor third-party claims related to the San Bruno accident during the nine months ended September 30, 2015 compared to the same period in 2014. No further insurance recoveries related to these claims are expected.

The Utility's future financial statements will continue to be impacted by additional charges associated with the Penalty Decision and unrecoverable pipeline-related expenses. (See "Key Factors Affecting Financial Results" above and Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses decreased by $18 million, or 3%, in the three months ended September 30, 2015 compared to the same period in 2014. This decrease primarily reflects the timing of the 2014 GRC decision that was issued in August 2014 and authorized the Utility to increase its depreciation rates. The decrease was partially offset by an increase in capital additions during the period.

The Utility's depreciation, amortization, and decommissioning expenses increased by $170 million, or 10%, in the nine months ended September 30, 2015 compared to the same period in 2014, primarily due to an increase in capital additions.

Interest Expense

The Utility's interest expenses increased by $32 million in the nine months ended September 30, 2015 compared to the same period in 2014, primarily due to the issuance of additional long-term debt.

Interest Income and Other Income, Net

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

Income Tax Provision

The income tax provision decreased by $43 million, or 37% in the three months ended September 30, 2015 as compared to the same period in 2014. The effective tax rates for the three months ended September 30, 2015 and 2014 were 19% and 13%, respectively. The decrease in the income tax provision in the three months ended September 30, 2015 is primarily due to lower pre-tax income resulting from the timing of the 2014 GRC decision (see "Operating Revenues" above) and the impact of the Penalty Decision recorded in 2015 with no comparable amount recorded for the same period in 2014. Under applicable accounting standards, charges resulting from the Penalty Decision are recorded at the statutory rate in the period incurred. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements).

The income tax provision decreased by $230 million, or 71%, in the nine months ended September 30, 2015 as compared to the same period in 2014. The effective tax rates for the nine months ended September 30, 2015 and 2014 were 12% and 20%, respectively. The decrease in the income tax provision and effective tax rate in the nine months ended September 30, 2015 is primarily due to lower pre-tax income resulting from the impact of the Penalty Decision.

SB 681 was introduced in June 2015 and proposed that the Utility be denied applicable state tax deductions for expenditures associated with the Penalty Decision. In September 2015, members of the California State Senate voted on this legislation and it did not receive a sufficient number of votes to pass. The authors of SB 681 requested to have the bill reconsidered and may reintroduce it in the future for subsequent votes. (See "Item 1A. Risk Factors" in Part II below).

Utility Revenues and Costs that did not Impact Earnings

Cost of Electricity

TheUtility's cost of electricity includes the costs of power purchased from third parties (including renewable energy resources), transmission, fuel used in its own generation facilities, fuel supplied to other facilities under power purchase agreements, costs to comply with California's cap-and-trade program, and realized gains and losses on price risk management activities. (See Note 7 of the Notes to the Condensed Consolidated Financial Statements.)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2015	2014	2015	2014
Cost of purchased power	$1,605	$1,684	$3,734	$4,083
Fuel used in own generation facilities	76	98	224	258
Total cost of electricity	$1,681	$1,782	$3,958	$4,341
Average cost of purchased power per kWh	$0.111	$0.114	$0.105	$0.101
Total purchased power (in millions of kWh) (1)	14,424	14,724	35,462	40,512

(1)The decrease in purchased power resulted from an increase in generation from the Utility's own generation facilities. Gas-fired generation increased in both the three and nine months ended September 30, 2015 and nuclear generation increased during the nine months ended September 30,2015 2015 as compared to the same periods in 2014.

The Utility's total purchased power is driven by customer demand, the availability of the Utility's own generation facilities (including the Diablo Canyon nuclear generation power plant and hydroelectric plants), and the cost-effectiveness of each source of electricity.

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Cost of Natural Gas

The Utility’s cost of natural gas includes the costs of procurement, storage, transportation of natural gas, costs to comply with California’s cap-and-trade program, 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, and changes in customer demand.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(in millions)	2015	2014	2015	2014
Cost of natural gas sold	$18	$102	$335	$591
Transportation cost of natural gas sold	32	32	107	103
Total cost of natural gas	$50	$134	$442	$694
Average cost per Mcf (1) of natural gas sold (2)	$0.69	$3.78	$2.46	$4.13
Total natural gas sold (in millions of Mcf)	26	27	136	143

(1) One thousand cubic feet
(2) Average cost of natural gas sold impacted by a decline in the market price of natural gas and a decrease in compliance costs.

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 pension contributions and public purpose programs costs. 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, finance capital expenditures, 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 CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect to recover its debt financing costs. 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.

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 has material stand-alone cash flows related to the issuance of equity and long-term debt, dividend payments, and borrowings and repayments under its revolving credit facility. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation forecasts that it will issue between $700 million and $800 million in common stock during 2015 primarily to fund equity contributions to the Utility. The Utility's equity needs will continue to be affected by unrecoverablepipeline-related expenses (includingcharges incurred to comply with the Penalty Decision) and by fines and penalties that may be imposed in connection with thematters described in "Enforcement and Litigation Matters" below. Common stock issuances by PG&E Corporation to fund these needs would have a material dilutive impact on PG&E Corporation's EPS.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. PG&E Corporation and the Utility maintain separate bank accounts and primarily invest their cash in money market funds. In addition to cash and cash equivalents, the Utility holds restricted cash that primarily consists of cash held in escrow pending the resolution of the remaining disputed claims made by electricity suppliers in the Utility's proceeding under Chapter 11 of the U.S. Bankruptcy Code. (See "Resolution of Remaining Chapter 11 Disputed Claims" in Note 9 of the Notes to the Condensed Consolidated Financial Statements). The Utility is uncertain when and how the remaining disputed claims will be resolved.

Financial Resources

Debt and Equity Financings

In February 2015, 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. In the first quarter of 2015, PG&E Corporation sold 1.4 million shares under this agreement for cash proceeds of $74 million, net of commissions paid of $1 million. No additional shares have been sold under the equity distribution agreement.

In August 2015, PG&E Corporation sold 6.8 million shares of its common stock in an underwritten public offering for cash proceeds of $352 million, net of fees.

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, 2015, 6.1 million shares were issued for cash proceeds of $263 million under these plans.

The proceeds from these sales were used for general corporate purposes, including the contribution of equity to the Utility. For the nine months ended September 30, 2015, PG&E Corporation made equity contributions to the Utility of $605 million, of which $300 million was used to pay a fine to the State General Fund as required by the Penalty Decision. Additionally, PG&E Corporation and the Utility expect to continue to issue long-term and short-term debt for general corporate purposes and to maintain the CPUC-authorized capital structure during 2015.

In June 2015, the Utility issued $400 million principal amount of 3.50% Senior Notes due June 15, 2025 and $100 million of 4.30% Senior Notes due March 15, 2045. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

Revolving Credit Facilities and Commercial Paper Program

On April 27, 2015, PG&E Corporation and the Utility amended and restated their respective $300 million and $3.0 billion revolving credit facilities. At September 30, 2015, PG&E Corporation and the Utility had $300 million and $2.1 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements)

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation own, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, these revolving credit facilities include usual and customary provisionsregarding events of default and covenants limiting liens, mergers, sales of all or substantially all of PG&E Corporation's and the Utility's assets, and other fundamental changes. At September 30, 2015, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

In September 2015, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $223 million, of which approximately $218 million was paid on October 15, 2015, to shareholders of record on September 30, 2015.

In September 2015, the Board of Directors of the Utility declared a common stock dividend of $179 million that was paid to PG&E Corporation on September 16, 2015.

In September 2015, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on November 15, 2015, to shareholders of record on October 30, 2015.

Utility Cash Flows

The Utility's cash flows were as follows:

(in millions)	Nine Months Ended September 30, 2015	2014
Net cash provided by operating activities	$2,932	$2,914
Net cash used in investing activities	(3,734)	(3,546)
Net cash provided by financing activities	809	652
Net change in cash and cash equivalents	$7	$20

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. During the nine months ended September 30, 2015, net cash provided by operating activities increased by $18 million compared to the same period in 2014. This increase was primarily due to lower purchased power costs (see "Cost of Electricity" under "Results of Operations – Utility Revenues and Costs that did not Impact Earnings" above) and offset by the payment of a $300 million fine to the State General Fund as required by the Penalty Decision.

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

- the shareholder-funded bill credit of $400 million to natural gas customers in 2016, as required by the Penalty Decision (see "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements);
- the timing and amounts of other fines or penalties that may be imposed in connection with the criminal prosecution of the Utility and the remaining investigations and other enforcement matters (see "Enforcement and Litigation Matters" below);
- the timing and outcome of ratemaking proceedings, including the 2015 GT&S rate case;
- the timing and amount of costs the Utility incurs, but does not recover, associated with its natural gas system (including costs to implement remedial measures and $850 million to pay for designated pipeline safety projects and programs, as required by the Penalty Decision);
- 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 principal and interest on these claims that the Utility will be required to pay.

Investing Activities

Net cash used in investing activities increased by $188 million during the nine months ended September 30, 2015 as compared to the same period in 2014. 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.

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 $5.3 billion in capital expenditures in 2015 and between $5.3 billion and $5.8 billion in 2016.

Financing Activities

During the nine months ended September 30, 2015, net cash provided by financing activities increased by $157 million compared to the same period in 2014. 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 short-term debt to fund temporary financing needs.

ENFORCEMENT AND LITIGATION MATTERS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to the enforcement and litigation matters described in Note 9 in the Condensed Consolidated Financial Statements. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's future financial results.

Department of Interior Inquiry

In September 2015, the Utility was notified that the U.S. Department of Interior ("DOI") had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the allegations contained in the superseding criminal indictment discussed above. The Utility will file its initial response on November 2, 2015 to demonstrate that it is a presently responsible contractor under federal procurement regulations and that it believes suspension or debarment is not appropriate. It is uncertain when or if further action will be taken.

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Pending Lawsuits and Claims

As of September 30, 2015, there were six purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims. Four of the complaints were consolidated in an action entitled Hind Bou-Salman, et. al. v. Peter A. Darbee, et. al. pending in the San Mateo County Superior Court. On August 28, 2015, the San Mateo County Superior Court overruled the demurrers filed by PG&E Corporation, the Utility and the individual director and officer defendants seeking to dismiss the Bou-Salman action, based upon the plaintiffs' failure to demand action by the Boards of PG&E Corporation and the Utility prior to filing the complaint. After the ruling, and pursuant to a writ previously filed by PG&E Corporation, the Utility, and the individual defendants, on September 3, 2015 the California Court of Appeal issued an order staying the Bou-Salman action pending the court's final determination whether to stay the matter altogether until the resolution of federal criminal proceedings against the Utility. On September 30, 2015, PG&E Corporation, the Utility, and the individual defendants filed an additional writ petition asking the Court of Appeal to review the lower court's August 28 decision overruling their demurrers. On October 22, 2015, the Court of Appeal issued a ruling stating that it was declining to review the August 28 decision. The other two derivative actions are entitled Tellardin v. PG&E Corp. et. al., pending in the San Mateo County Superior Court, and Iron Workers Mid-South Pension Fund v. Johns, et. al., pending in the United States District Court for the Northern District of California. The Iron Workers matter remains stayed by agreement of the parties, pending further developments in the Bou-Salman action. There is a case management conference set in the Tellardin action for December 21, 2015. In addition, an Evaluation Committee the Board formed in May 2015 continues to consider responses to a demand on the board by the plaintiff in the Tellardin matter.

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

RATEMAKING 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 2014 Form 10-K was filed with the SEC are discussed below.

2017 General Rate Case

On September 1, 2015, the Utility filed its 2017 GRC application with the CPUC. In the 2017 GRC, the Utility has requested that the CPUC determine the annual amount of base revenues (or “revenue requirements”) that the Utility will be authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. (The Utility’s revenue requirements for other portions of its operations, such as electric transmission, natural gas transmission and storage services, and electricity and natural gas purchases, are authorized in other regulatory proceedings overseen by the CPUC or the FERC.) In its application, the Utility requested a revenue requirement increase of $457 million, as compared to authorized base revenues for 2016, as shown in the following tables:

Line of Business: (in millions)	Amounts Requested In the GRC Application	Amounts Currently Authorized For 2016	Increase Compared to Currently Authorized Amounts
Electric distribution	$4,376	$4,212	$164
Gas distribution	1,827	1,742	85
Electric generation	2,170	1,962	208
Total revenue requirements	$8,373	$7,916	$457
Cost Category: (in millions)			
Operations and maintenance	$1,833	$1,664	$169
Customer services	367	319	48
Administrative and general	978	1,011	(33)
Less: Revenue credits	(140)	(131)	(9)
Franchise fees, taxes other than income, and other adjustments	185	37	148
Depreciation (including costs of asset removal), return, and income taxes	5,150	5,016	134
Total revenue requirements	$8,373	$7,916	$457

In its application, the Utility stated that over the 2017-2019 GRC period, the Utility plans to make average annual capital investments of approximately $4 billion in electric distribution, natural gas distribution and electric generation infrastructure, and to improve safety, reliability, and customer service. (These annual investments would be incremental to the Utility’s capital expenditures for electric and natural gas transmission infrastructure.) The Utility also requested that the CPUC establish a ratemaking mechanism that would increase the Utility’s authorized revenues in 2018 and 2019, primarily to reflect increases in rate base due to capital investments in infrastructure and, to a lesser extent, anticipated increases in wages and other expenses. The Utility estimates that this mechanism would result in increases in revenue of $489 million in 2018 and an additional $390 million in 2019.

In October 2015, the Utility filed supplemental testimony to reduce its original revenue requirement request by approximately $17 million per year based on its forecast that it will incur approximately $61 million for unrecoverable costs to implement the remedies ordered in the Penalty Decision.

The Utility expects that a procedural schedule will be issued to set the dates for public hearings, the submission of testimony by the ORA and other interested parties, evidentiary hearings, and the submission of briefs. After the submission of briefs, the ALJ will issue a proposed decision for consideration by the CPUC. In its application, the Utility requested that the CPUC issue a final decision by December 31, 2016.

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2015 Gas Transmission and Storage Rate Case

In the 2015 GT&S rate case, the Utility requested that the CPUC authorize a 2015 revenue requirement of $1.263 billion to recover anticipated costs of providing natural gas transmission and storage services, an increase of $532 million over currently authorized amounts. The Utility also requested attrition increases of $83 million in 2016 and $142 million in 2017. The Utility requested that the CPUC authorize the Utility's forecast of its 2015 weighted average rate base for its gas transmission and storage business of $3.44 billion, which includes capital spending above authorized levels for the prior rate case period.

The ORA has recommended a 2015 revenue requirement of $1.044 billion, an increase of $329 million over authorized amounts. TURN recommended that the Utility not recover costs associated with hydrostatic testing for pipeline segments placed in service after January 1, 1956, as well as certain other work that TURN considers to be remedial. 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 capital expenditures during this period 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.

The Utility also has proposed changes to the revenue sharing mechanism authorized in the last GT&S rate case (covering 2011-2014) that subjected a portion of the Utility's transportation and storage revenue requirement to market risk. The Utility proposed full balancing account treatment that allows for recovery of the Utility's authorized transportation and storage revenue requirements (except for the revenue requirement associated with the Utility's 25% interest in the Gill Ranch storage field).

Based on the scoping ruling and procedural schedule that was issued on June 11, 2015, the CPUC plans to issue an initial decision to authorize revenue requirements followed by a second decision to reduce the authorized revenue requirements by the costs of designated safety-related projects and programs up to the $850 million maximum cost disallowance imposed by the Penalty Decision. (See Note 9 in the Condensed Consolidated Financial Statements for more information about the CPUC's Penalty Decision.) (In accordance with an earlier CPUC decision regarding the Utility's violation of the CPUC's ex parte communication rules made in the GT&S rate case, the first decision could disallow the Utility from recovering up to a five-month portion of the revenue increase that may otherwise have been authorized.)It is uncertain how the second CPUC decision will identify the costs that are counted toward the $850 million shareholder-funded obligation. If the Utility's actual costs exceed costs that the CPUC counts towards the $850 million maximum, the Utility would record additional charges if such costs are not otherwise authorized by the CPUC.

The authorized revenue requirements in the GT&S rate case would be retroactive to January 1, 2015. Under the procedural schedule, the CPUC's first decision to authorize revenue requirements likely will not be issued until 2016 and the second decision to determine the revenue requirement reduction will follow. (The ruling states that, in any event, the case would be completed within 18 months of the date of the ruling, or by December 2016.) Based on the procedural schedule, it is unlikely that the Utility will be able to recognize any increase in its GT&S revenue in 2015.

FERC TO Rate Cases

On September 30, 2015, the FERC approved a settlement that sets the Utility's 2015 retail electric transmission revenue requirement at $1.201 billion, a $161 million increase over the currently authorized revenue requirement of $1.040 billion.

On July 29, 2015, the Utility requested that the FERC approve a 2016 retail electric transmission revenue requirement of $1.515 billion. The proposed amount reflects a $314 million increase over the settled revenue requirement of $1.201 billion. The Utility forecasts that it will make investments of $1.246 billion in 2016 in various capital projects. The Utility's forecasted rate base for 2016 is $5.85 billion, compared to forecasted rate base of $5.12 billion in 2015. The Utility has requested that the FERC approve a 10.96% return on equity. On September 30, 2015, the FERC accepted the proposed revenue requirement, subject to hearing and refund, and established March 1, 2016 as the effective date for rate changes. Hearings are being held in abeyance pending settlement discussions among the parties.

CPUC Investigation of the Utility's Safety Culture

On August 27, 2015, the CPUC began a formal investigation into whether the organizational culture and governance of PG&E Corporation and the Utility prioritize safety and adequately direct resources to promote accountability and achieve safety goals and standards. The CPUC directed the SED to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents. The CPUC authorized the SED to engage a consultant to assist in the SED's investigation and the preparation of a report containing the SED's assessment.

The CPUC stated that the initial phase of the proceeding was categorized as ratesetting because it will consider issues both of fact and policy and because the Utility and PG&E Corporation do not face the prospect of fines, penalties, or remedies in this phase. Upon completion of the consultant's report, the assigned Commissioner will determine the scope of and next actions in the proceeding.The timing scope and potential outcome of the investigation are uncertain.

LEGISLATIVE AND REGULATORY INITIATIVES

The California Legislature and the CPUC have adopted requirements and policies to accommodate the growth in distributed electric generation resources (including solar installations), increase the amount of renewable energy delivered to customers, foster the development of a state-wide electric vehicle charging infrastructure to encourage the use of electric vehicles, and promote customer energy efficiency and demand response programs. In addition, the CPUC continues to implement state law requirements to reform electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, implement new rules and rates for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate), and allow customers to have greater control over their energy use. CPUC proceedings related to some of these matters are discussed below.

The Utility's ability to recover its costs, including investments associated with legislative and regulatory initiatives, as well as its electricity procurement and other operating costs, will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas service.

New Renewable Energy Targets

In October 2015, the California Governor signed SB 350 which, effective January 1, 2016, increases the amount of renewable energy that must be delivered by most load-serving entities, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period to 50% of their total annual retail sales by the end of the 2028- 2030 compliance period and in each compliance period thereafter. SB 350 includes increasing interim renewable energy targets for the periods between 2020 and 2030 and continues to include compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance periods. The Utility will incur additional costs to procure renewable energy to meet the new renewable energy targets which the Utility expects will continue to be recoverable from customers as "pass-through" costs. The Utility also may be subject to penalties for failure to meet the higher targets. The CPUC is required to open a new rulemaking proceeding to adopt regulations to implement the higher targets.

Electric Distribution Resources Plan

As required by California law, on July 1, 2015, the Utility filed its proposed electric distribution resources plan for approval by the CPUC. The Utility's plan identifies optimal locations on its electric distribution system for deployment of distributed energy resources. The Utility's proposal is designed to allow energy technologies to be interconnected with each other and integrated into the larger grid while continuing to provide customers with safe, reliable and affordable electric service. The Utility envisions a future electric grid, titled the Grid of Things™, that would allow customers to choose new advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service. The Utility's 2017 GRC includes a request to recover some of the investment costs that it forecasts it will incur under its proposed electric distribution resources plan.

Electric Rate Reform and Net Energy Metering ("NEM")

On July 3, 2015, the CPUC approved a final decision to authorize the California investor–owned utilities to gradually flatten their tiered residential electric rate structures from four tiers to two tiers by January 1, 2019. The decision also allows the imposition of a surcharge on customers with extremely high electricity use beginning in 2017. The decision requires the Utility to file a proposal by January 1, 2018, to charge residential customers based on time-of-use rates unless customers elect otherwise (known as "default time-of-use rates"). The Utility also may propose to impose a fixed charge on customers. Under the CPUC's decision, default time-of-use rates must be implemented before the CPUC will permit the imposition of a fixed charge. The CPUC also approved increased minimum bill charges for residential customers.

In July 2014, the CPUC began a new rulemaking proceeding to develop new net energy metering rules and rates to more accurately reflect the utilities' costs of providing service to such customers while continuing to encourage the development and installation of renewable distributed generation technologies. On August 3, 2015, the Utility filed its proposal for new net energy metering rules and rates. The CPUC is expected to issue a decision by December 2015.

Electric Vehicle (EV) Infrastructure Development

In December 2014, the CPUC issued a decision adopting a policy to expand the California utilities' role in developing an EV charging infrastructure to support California's climate goals. On February 9, 2015, the Utility filed an application requesting that the CPUC approve the Utility's proposal to deploy, own, and maintain more than 25,000 EV charging stations and the associated infrastructure. The Utility proposed to engage with third party EV service providers to operate and maintain the charging stations. The Utility requested that the CPUC approve forecasted capital expenditures of $551 million over the 5 year deployment period.

On September 4, 2015, the assigned CPUC Commissioner and the ALJ issued a scoping memo and procedural schedule that required the Utility to supplement its application by submitting a more phased deployment approach that will be considered in a first phase of the proceeding. On October 12, 2015, the Utility submitted supplemental testimony presenting two separate proposals. In its first proposal, the Utility has requested that the CPUC approve approximately $70 million in capital expenditures to deploy and own 2,510 EV charging stations over approximately 2 years. In its second proposal, the Utility has requested that the CPUC approve approximately $187 million in capital expenditures to deploy and own 7,530 EV charging stations over approximately 3 years. Under the CPUC's schedule, a proposed decision for the first phase of the proceeding is expected to be issued by June 2016. Further deployment of EV charging stations would be considered in a second phase of the proceeding depending on the outcome of the first phase.

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, such as groundwater contamination caused by hexavalent chromium used in the past at the Utility's natural gas compressor stations; the reporting and reduction of carbon dioxide and other greenhouse gas emissions; the discharge of pollutants into the air, water, and soil; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements, as well as "Item 1A. Risk Factors" and Note 14 in the 2014 Form 10-K.)

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 "Purchase Commitments" in Note 9 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 of Financial Condition and Results of Operations – Contractual Commitments in the 2014 Form 10-K.

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 2014 Form 10-K (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 2014 Form 10-K. There were no significant developments to the Utility and PG&E Corporation's risk management activities during the nine months ended September 30, 2015.

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 2014 Form 10-K.

ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

See the discussion above in Note 2 of the Notes to the Condensed Consolidated Financial Statements.

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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 outcome and timing of the 2015 GT&S rate case, including the amount of revenue disallowance that may be imposed as a penalty for improper ex parte communications and how the authorized revenue requirements are reduced to reflect the disallowance of costs associated with designated safety-related projects and programs as required by the Penalty Decision;
- the outcomes of the federal criminal prosecution of the Utility, the CPUC's investigation of the Utility's natural gas distribution record-keeping practices, the SED's unresolved enforcement action matters, and the other investigations that have been or may be commenced relating to the Utility's compliance with natural gas-related laws and regulations, and the amount of fines, penalties, and remedial costs that the Utility may incur in connection with such matters;
- the timing and outcome of the CPUC's investigation and the pending criminal investigations relating to communications between the Utility and the CPUC that may have violated the CPUC's rules regarding ex parte communications or are otherwise alleged to be improper, and whether such matters negatively affect the final decisions to be issued in the 2015 GT&S rate case or other ratemaking proceedings;
- whether PG&E Corporation and the Utility are able to repair the harm to their reputations caused by the criminal prosecution of the Utility, the state and federal investigations of natural gas incidents, improper communications between the CPUC and the Utility; and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;
- the restrictions on communications between the Utility and the CPUC that have been imposed by the CPUC that, along with continuing public criticism of the Utility and the CPUC, may make it more difficult for the Utility to sustain or repair a constructive working relationship with the CPUC and achieve balanced regulatory outcomes;
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- the timing and outcome of ratemaking proceedings (such as the 2015 GT&S rate case, the 2017 GRC and the TO rate cases) and other regulatory proceedings (such as the recently re-opened proceeding related to the Utility’s 2006-2008 energy efficiency programs and the proceeding to consider the Utility’s proposal to develop an EV charging infrastructure);
- whether the Utility can control its costs within the authorized levels of spending, the extent to which the Utility incurs unrecoverable costs that are higher than the forecasts of such costs, and changes in cost forecasts or the scope and timing of planned work resulting from changes in customer demand for electricity and natural gas or other reasons;
- the amount and timing of additional common stock and debt 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 shareholder-funded costs to complete designated safety projects and programs as ordered in the Penalty Decision) and fines;
- the outcome of the recently opened CPUC investigation into the Utility’s safety culture, and future legislative or regulatory actions that may be taken to require the Utility to restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;

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- the outcomes of future investigations 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 outcomes;

- the impact of environmental 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 costs in rates or from other sources; and the ultimate amount of environmental 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 resume its pursuit to renew the two Diablo Canyon operating licenses, and if so, whether the licenses are renewed;

- the impact of droughts or other weather-related conditions or events, wildfires, 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 greenhouse gases, 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 whether the Utility can timely recover renewable energy procurement costs;

- the impact that reductions in customer demand for electricity and natural gas have on the Utility's ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility's business strategy to address the impact of growing distributed and renewable generation resources and changing customer demands is successful;

- 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;

- 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 amount and timing of charges reflecting probable liabilities for third-party claims; 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; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

- 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;

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- 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 CPUC's pending investigations, the criminal prosecution, and other enforcement matters 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, including whether state law is enacted to prohibit the Utility from claiming tax deductions for costs associated with designated safety-related projects and programs that are disallowed by the Penalty Decision; 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 2014 Form 10-K and in Part II, 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, 2015, 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, 2015, 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 9 of the Notes to the Condensed Consolidated Financial Statements.

CPUC Investigations Related to Natural Gas Transmission

For description of this matter, see "Part II, Item 1. Legal Proceedings" in the Form 10-Q for the quarters ended March 31 and June 30, 2015. In addition, see discussion entitled "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements.

Federal Criminal Indictment

For description of this matter, see "Part II, Item 1. Legal Proceedings" in the Form 10-Q for the quarters ended March 31 and June 30, 2015. In addition, see discussion entitled "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements.

Litigation Related to the San Bruno Accident and Natural Gas Spending

As of September 30, 2015, there were six purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated in an action entitled Hind Bou-Salman, et. al. v. Peter A. Darbee, et. al. pending in the San Mateo County Superior Court. On August 28, 2015, the San Mateo County Superior Court overruled the demurrers filed by PG&E Corporation, the Utility and the individual director and officer defendants seeking to dismiss the Bou-Salman action, based upon the plaintiffs' failure to demand action by the Boards of PG&E Corporation and the Utility prior to filing the complaint. After the ruling, and pursuant to a writ previously filed by PG&E Corporation, the Utility, and the individual defendants, on September 3, 2015 the California Court of Appeal issued an order staying the Bou-Salman action pending the court's final determination whether to stay the matter altogether until the resolution of federal criminal proceedings against the Utility. On September 30, 2015, PG&E Corporation, the Utility, and the individual defendants filed an additional writ petition asking the Court of Appeal to review the lower court's August 28 decision overruling their demurrers. On October 22, 2015, the Court of Appeal issued a ruling stating that it was declining to review the August 28 decision. The other two derivative actions are entitled Tellardin v. PG&E Corp. et. al., pending in the San Mateo County Superior Court, and Iron Workers Mid-South Pension Fund v. Johns, et. al., pending in the United States District Court for the Northern District of California. The Iron Workers matter remains stayed by agreement of the parties, pending further developments in the Bou-Salman action. There is a case management conference set in the Tellardin action for December 21, 2015. In addition, an Evaluation Committee the Board formed in May 2015 continues to consider a demand on the Boards by the plaintiff in the Tellardin matter.

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

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. In addition, see "Part I, Item 3. Legal Proceedings" in the 2014 Form 10-K, and "Part II, Item 1. Legal Proceedings" in the Form 10-Q for the quarters ended March 31 and June 30, 2015.

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" above in Part 1, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 9 of the Notes to the Condensed Consolidated Financial Statements. In addition, see "Part I, Item 3. Legal Proceedings" in the 2014 Form 10-K.

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 2014 Form 10-K.

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 2014 Form 10-K 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 future financial results will continue to be materially affected as the Utility complies with the Penalty Decision and also may be materially affected by the outcomes of the 2015 GT&S rate case, the CPUC investigative enforcement proceeding regarding the Utility's natural gas distribution record-keeping, the ongoing federal criminal prosecution of the Utility, and the other federal, state and regulatory proceedings discussed above. In addition, their financial results may be materially affected if the Utility is required to refund incentive awards or incur other obligations with respect to its 2006-2008 energy efficiency programs.

PG&E Corporation's EPS will be materially affected by dilutive common stock issuances needed to fund equity contributions to the Utility to comply with the terms of the Penalty Decision, as discussed above in Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations ("MD&A") and Note 9 of the Condensed Consolidated Financial Statements. The Utility will incur material unrecoverable costs to meet the Penalty Decision's requirement to fund safety-related projects and programs to be identified by the CPUC in the GT&S rate case. Depending on how the CPUC designates pipeline safety-related projects and programs the Utility is required to fund, and how the Utility's associated costs are counted toward meeting the $850 million maximum disallowance, the ultimate amount of unrecoverable pipeline-related costs the Utility incurs may be higher than current forecasts. In addition, the Penalty Decision requires the Utility to implement various remedial measures which the CPUC estimated would cost $50 million. Actual costs to implement the remedies could be higher. The Penalty Decision also requires the SED to review the Utility's gas transmission operations (including review of the Utility's compliance with the remedies ordered by the Penalty Decision) and to perform annual audits (for a minimum of ten years) of the Utility's record-keeping practices. The Utility could incur material charges, including fines and other penalties, depending on the outcome of these future audits.

The ultimate financial impact of the Penalty Decision also could be affected by the tax treatment of the costs the Utility incurs to comply with the Penalty Decision. Although proposed state legislation to prohibit the Utility from claiming state tax deductions for charges associated with the Penalty Decision was defeated in September 2015, similar legislation may be passed in the future.

The Utility could incur material charges, including fines and other penalties, in connection with the CPUC's investigation of the Utility's compliance with natural gas distribution record-keeping practices, and the self-reports the Utility has submitted to the CPUC in accordance with the SED's safety citation program, and the Utility's efforts to identify and remove encroachments from transmission pipeline rights of way.

The CPUC has not yet taken action with respect to the City of San Bruno's allegations that the Utility violated the CPUC's rules regarding ex parte communications, or with respect to the Utility's self-reports about communications that may constitute or describe ex parte communications. Federal and state law enforcement authorities also have begun investigations in connection with these matters. The CPUC, or federal or state law enforcement authorities, could take enforcement action against the Utility with respect to these matters, and additional fines or penalties could be imposed on the Utility which could materially affect PG&E Corporation's and the Utility's financial results.

If the Utility is convicted of federal criminal charges, the Utility could be required to pay fines. Based on the superseding indictment's allegations, the maximum alternative fine would be approximately $1.13 billion. The Utility also could incur a material amount of costs to comply with remedial measures that may be imposed on the Utility, such as a requirement that the Utility's natural gas operations be supervised by a third-party monitor. The Utility was informed that the U.S. Attorney's Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. The U.S. Attorney's Office in San Francisco also continues to investigate matters related to the indicted case discussed above. It is uncertain whether any additional charges will be brought against the Utility.

Further, the CPUC has begun a new investigation to examine the Utility's safety culture and practices and has directed the SED to engage a consultant to evaluate the Utility's and PG&E Corporation's organizational culture, governance, policies, practices, and accountability metrics in relation to the Utility's record of operations, including its record of safety incidents. Although the initial phase of the proceeding has been categorized as rate setting, the assigned Commissioner will determine the scope of and next actions in the proceeding following the completion of the consultant's report. The timing, scope and potential outcome of the investigation and successor proceedings are uncertain.

PG&E Corporation and the Utility may incur material liability in connection with the recent wildfires in Northern California.

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. Although the cause of the fire has not yet been determined, the Utility could incur material liability for claims from third parties, including claims for property damage, fire suppression costs, personal injury, or other claims. If insurance recoveries are unavailable or insufficient to cover such losses, PG&E Corporation's and the Utility's financial condition or results of operations could be materially affected. The Utility also could be subject to material fines, or penalties or disallowances if the CPUC or other law enforcement agency brought enforcement action against the Utility.

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

During the quarter ended September 30, 2015, PG&E Corporation made equity contributions totaling $420 million to the Utility in order to maintain the 52% common equity component of the Utility's CPUC-authorized capital structure. Neither PG&E Corporation nor the Utility made any sales of unregistered equity securities during the quarter ended September 30, 2015.

Issuer Purchases of Equity Securities

During the quarter ended September 30, 2015, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended September 30, 2015, 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, 2015 was 1.88. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the nine months ended September 30, 2015 was 1.86. 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, 2015 was 1.87. 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

3	Bylaws of Pacific Gas and Electric Company amended as of August 17, 2015 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed on July 14, 2015 (File No. 1-2348), Exhibit 99.2)
*10.1	Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated October 1, 2015
*10.2	Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated October 1, 2015
*10.3	PG&E Corporation 2005 Supplemental Retirement Savings Plan as amended effective September 15, 2015
12.1	Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company
12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
31.1	Certifications of the Principal Executive Officer and the Principal Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002
31.2	Certifications of the Principal Executive Officers and the Principal Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002
**32.1	Certifications of the Principal Executive Officer and the Principal Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002
**32.2	Certifications of the Principal Executive Officers and the Principal Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document
101.SCH	XBRL Taxonomy Extension Schema Document
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
101.LAB	XBRL Taxonomy Extension Labels Linkbase Document
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document

*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, 2015

EXHIBIT INDEX

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