PG&E Corp
Form 10-Q
July 28, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C., 20549
FORM 10-Q
(Mark One)

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

For the quarterly period ended June 30, 2016

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 77 Beale Street P.O. Box 770000 San Francisco, California 94177	Pacific Gas and Electric Company 77 Beale Street P.O. Box 770000 San Francisco, California 94177

Address of principal executive offices, including zip code

PG&E Corporation (415) 973-1000	Pacific Gas and Electric Company (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 July 19, 2016:	
PG&E Corporation:	498,506,353
Pacific Gas and Electric Company:	264,374,809

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

FOR THE QUARTERLY PERIOD ENDEDJUNE 30, 2016

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GLOSSARY

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

2015 Form 10-K	PG&E Corporation and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2015
2016 Q1 Form 10-Q	PG&E Corporation and Pacific Gas and Electric Company's combined Quarterly Report on Form 10-Q for the quarter ended March 31, 2016
AFUDC	allowance for funds used during construction
ALJ	Administrative Law Judge
ARO(s)	asset retirement obligation(s)
ASU	Accounting Standards Update issued by the FASB (see below)
Cal Fire	California Department of Forestry and Fire Protection
CAISO	California Independent System Operator Corporation
Central Coast Water Board	Central Coast Regional Water Quality Control Board
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DER	distributed energy resources
Diablo Canyon	Diablo Canyon nuclear power plant
DOI	U.S. Department of the Interior
DTSC	California Department of Toxic Substances Control
EMANI	European Mutual Association for Nuclear Insurance
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
GHG	greenhouse gas
GRC	general rate case
GT&S	gas transmission and storage
GWH	gigawatt-hours
IOU(s)	investor-owned utility(ies)
IRS	Internal Revenue Service
NAV	net asset value
NDCTP	Nuclear Decommissioning Cost Triennial Proceedings
NEIL	Nuclear Electric Insurance Limited
NEM	Net Energy Metering
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
OII	order instituting investigation
ORA	Office of Ratepayer Advocates

POD	presiding officer's decision
PSEP	pipeline safety enhancement plan
PV	photovoltaic
Regional Board	California Regional Water Control Board, Lahontan Region
RPS	Renewable Portfolio Standards
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
TO	transmission owner
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
VIE(s)	variable interest entity(ies)

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PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	2016	2015	2016	2015
Operating Revenues				
Electric	$3,465	$3,463	$6,596	$6,476
Natural gas	704	754	1,547	1,640
Total operating revenues	4,169	4,217	8,143	8,116
Operating Expenses				
Cost of electricity	1,156	1,277	2,106	2,277
Cost of natural gas	75	118	297	392
Operating and maintenance	1,838	1,484	3,848	3,407
Depreciation, amortization, and decommissioning	699	651	1,396	1,282
Total operating expenses	3,768	3,530	7,647	7,358
Operating Income	401	687	496	758
Interest income	5	3	9	4
Interest expense	(207)	(192)	(410)	(381)
Other income, net	23	18	50	76
Income Before Income Taxes	222	516	145	457
Income tax provision (benefit)	12	110	(175)	17
Net Income	210	406	320	440
Preferred stock dividend requirement of subsidiary	4	4	7	7
Income Available for Common Shareholders	$206	$402	$313	$433
Weighted Average Common Shares Outstanding, Basic	497	480	495	479
Weighted Average Common Shares Outstanding, Diluted	498	483	497	483
Net Earnings Per Common Share, Basic	$0.41	$0.84	$0.63	$0.90
Net Earnings Per Common Share, Diluted	$0.41	$0.83	$0.63	$0.90
Dividends Declared Per Common Share	$0.49	$0.46	$0.95	$0.91

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited) Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in millions)	2016	2015	2016	2015
Net Income	$210	$406	$320	$440
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, $0, $0 and $12, at respective dates)	-	-	-	(17)
Total other comprehensive income (loss)	-	-	-	(17)
Comprehensive Income	210	406	320	423
Preferred stock dividend requirement of subsidiary	4	4	7	7
Comprehensive Income Attributable to				
Common Shareholders	$206	$402	$313	$416

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
	June 30,	December 31,
(in millions)	2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	$189	$123
Restricted cash	235	234
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $53 and $54 at respective dates)	1,039	1,106
Accrued unbilled revenue	957	855
Regulatory balancing accounts	1,697	1,760
Other	567	286
Regulatory assets	464	517
Inventories:		
Gas stored underground and fuel oil	123	126
Materials and supplies	346	313
Income taxes receivable	234	155
Other	284	338
Total current assets	6,135	5,813
Property, Plant, and Equipment		
Electric	50,872	48,532
Gas	17,123	16,749
Construction work in progress	2,096	2,059
Other	2	2
Total property, plant, and equipment	70,093	67,342
Accumulated depreciation	(21,496)	(20,619)
Net property, plant, and equipment	48,597	46,723
Other Noncurrent Assets		
Regulatory assets	7,315	7,029
Nuclear decommissioning trusts	2,546	2,470
Income taxes receivable	147	135
Other	1,187	1,064
Total other noncurrent assets	11,195	10,698
TOTAL ASSETS	$65,927	$63,234

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, except share amounts)	June 30, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$ 1,529	$ 1,019
Long-term debt, classified as current	160	160
Accounts payable:		
Trade creditors	1,313	1,414
Regulatory balancing accounts	654	715
Other	527	398
Disputed claims and customer refunds	461	454
Interest payable	214	206
Other	1,793	1,997
Total current liabilities	6,651	6,363
Noncurrent Liabilities		
Long-term debt	16,525	15,925
Regulatory liabilities	6,547	6,321
Pension and other postretirement benefits	2,631	2,622
Asset retirement obligations	4,612	3,643
Deferred income taxes	9,556	9,206
Other	2,407	2,326
Total noncurrent liabilities	42,278	40,043
Commitments and Contingencies (Note 9)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares;		
498,143,219 and 492,025,443 shares outstanding at respective dates	11,616	11,282
Reinvested earnings	5,137	5,301
Accumulated other comprehensive loss	(7)	(7)
Total shareholders' equity	16,746	16,576
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	16,998	16,828
TOTAL LIABILITIES AND EQUITY	$ 65,927	$ 63,234

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PG&E CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Six Months Ended June 30,	
(in millions)	2016	2015
Cash Flows from Operating Activities		
Net income	$320	$440
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,396	1,282
Allowance for equity funds used during construction	(54)	(53)
Deferred income taxes and tax credits, net	350	219
Disallowed capital expenditures	425	128
Other	179	149
Effect of changes in operating assets and liabilities:		
Accounts receivable	(338)	(241)
Inventories	(30)	20
Accounts payable	179	78
Income taxes receivable/payable	(79)	6
Other current assets and liabilities	308	77
Regulatory assets, liabilities, and balancing accounts, net	(769)	(62)
Other noncurrent assets and liabilities	(106)	(184)
Net cash provided by operating activities	1,781	1,859
Cash Flows from Investing Activities		
Capital expenditures	(2,651)	(2,410)
Proceeds from sales and maturities of nuclear decommissioning trust investments	721	779
Purchases of nuclear decommissioning trust investments	(762)	(879)
Other	6	24
Net cash used in investing activities	(2,686)	(2,486)
Cash Flows from Financing Activities		
Net issuances (repayments) of commercial paper, net of discount of $3 and $2 at respective dates	257	681
Short-term debt financing	250	-
Short-term debt matured	-	(300)
Proceeds from issuance of long-term debt, net of discount and issuance costs of $6 and $14 at respective dates	594	486
Common stock issued	289	252
Common stock dividends paid	(440)	(424)
Other	21	30
Net cash provided by financing activities	971	725
Net change in cash and cash equivalents	66	98
Cash and cash equivalents at January 1	123	151
Cash and cash equivalents at June 30	$189	$249

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Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(357)	$(334)
Income taxes, net	54	-
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	$244	$219
Capital expenditures financed through accounts payable	309	177
Noncash common stock issuances	10	10

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited)			
	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2016	2015	2016	2015
Operating Revenues				
Electric	$3,465	$3,462	$6,597	$6,476
Natural gas	704	754	1,547	1,640
Total operating revenues	4,169	4,216	8,144	8,116
Operating Expenses				
Cost of electricity	1,156	1,277	2,106	2,277
Cost of natural gas	75	118	297	392
Operating and maintenance	1,837	1,483	3,848	3,406
Depreciation, amortization, and decommissioning	700	651	1,396	1,282
Total operating expenses	3,768	3,529	7,647	7,357
Operating Income	401	687	497	759
Interest income	4	3	8	4
Interest expense	(204)	(189)	(405)	(376)
Other income, net	21	20	45	46
Income Before Income Taxes	222	521	145	433
Income tax provision (benefit)	13	115	(172)	23
Net Income	209	406	317	410
Preferred stock dividend requirement	4	4	7	7
Income Available for Common Stock	$205	$402	$310	$403

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited) Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in millions)	2016	2015	2016	2015
Net Income	$209	$406	$317	$410
Other Comprehensive Income				
Pension and other postretirement benefit plans obligations				
(net of taxes of $0, $0, $0 and $0, at respective dates)	1	-	1	-
Total other comprehensive income (loss)	1	-	1	-
Comprehensive Income	$210	$406	$318	$410

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
	June 30,	December 31,
(in millions)	2016	2015
ASSETS		
Current Assets		
Cash and cash equivalents	$120	$59
Restricted cash	235	234
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $53 and $54 at respective dates)	1,039	1,106
Accrued unbilled revenue	957	855
Regulatory balancing accounts	1,697	1,760
Other	566	284
Regulatory assets	464	517
Inventories:		
Gas stored underground and fuel oil	123	126
Materials and supplies	346	313
Income taxes receivable	208	130
Other	283	338
Total current assets	6,038	5,722
Property, Plant, and Equipment		
Electric	50,872	48,532
Gas	17,123	16,749
Construction work in progress	2,096	2,059
Total property, plant, and equipment	70,091	67,340
Accumulated depreciation	(21,494)	(20,617)
Net property, plant, and equipment	48,597	46,723
Other Noncurrent Assets		
Regulatory assets	7,315	7,029
Nuclear decommissioning trusts	2,546	2,470
Income taxes receivable	147	135
Other	1,072	958
Total other noncurrent assets	11,080	10,592
TOTAL ASSETS	$65,715	$63,037

See accompanying Notes to the Condensed Consolidated Financial Statements.

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PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
	June 30,	December 31,
(in millions, except share amounts)	2016	2015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 1,529	$ 1,019
Long-term debt, classified as current	160	160
Accounts payable:		
Trade creditors	1,313	1,414
Regulatory balancing accounts	654	715
Other	558	418
Disputed claims and customer refunds	461	454
Interest payable	211	203
Other	1,522	1,750
Total current liabilities	6,408	6,133
Noncurrent Liabilities		
Long-term debt	16,177	15,577
Regulatory liabilities	6,547	6,321
Pension and other postretirement benefits	2,540	2,534
Asset retirement obligations	4,612	3,643
Deferred income taxes	9,839	9,487
Other	2,364	2,282
Total noncurrent liabilities	42,079	39,844
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	7,495	7,215
Reinvested earnings	8,149	8,262
Accumulated other comprehensive income	4	3
Total shareholders' equity	17,228	17,060
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 65,715	$ 63,037

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Six Months Ended June 30,	
(in millions)	2016	2015
Cash Flows from Operating Activities		
Net income	$317	$410
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, amortization, and decommissioning	1,396	1,282
Allowance for equity funds used during construction	(54)	(53)
Deferred income taxes and tax credits, net	352	219
Disallowed capital expenditures	425	128
Other	144	119
Effect of changes in operating assets and liabilities:		
Accounts receivable	(339)	(242)
Inventories	(30)	20
Accounts payable	190	134
Income taxes receivable/payable	(78)	8
Other current assets and liabilities	310	67
Regulatory assets, liabilities, and balancing accounts, net	(769)	(62)
Other noncurrent assets and liabilities	(95)	(170)
Net cash provided by operating activities	1,769	1,860
Cash Flows from Investing Activities		
Capital expenditures	(2,651)	(2,410)
Proceeds from sales and maturities of nuclear decommissioning trust investments	721	779
Purchases of nuclear decommissioning trust investments	(762)	(879)
Other	6	24
Net cash used in investing activities	(2,686)	(2,486)
Cash Flows from Financing Activities		
Net issuances (repayments) of commercial paper, net of discount of $3 and $2 at respective dates	257	676
Short-term debt financing	250	-
Short-term debt matured	-	(300)
Proceeds from issuance of long-term debt, net of discount and issuance costs of $6 and $14 at respective dates	594	486
Preferred stock dividends paid	(7)	(7)
Common stock dividends paid	(423)	(358)
Equity contribution from PG&E Corporation	280	185
Other	27	37
Net cash provided by financing activities	978	719
Net change in cash and cash equivalents	61	93
Cash and cash equivalents at January 1	59	55

Cash and cash equivalents at June 30	$120	$148

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Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(352)	$(330)
Income taxes, net	54	-
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$309	$177

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. The Utility is primarily regulated by the CPUC and the FERC. In addition, the NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities.

This quarterly report on Form 10-Q is a combined report of PG&E Corporation and the Utility. PG&E Corporation's Condensed Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and 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, as the companies assess financial performance and allocate resources on a consolidated basis.

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, 2015 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in the 2015 Form 10-K. This quarterly report should be read in conjunction with the 2015 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 2015 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 June 30, 2016, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement, analyzed the variability in the VIE's gross margin, and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at June 30, 2016, it did not consolidate any of them.

Asset Retirement Obligations

Detailed studies of the cost to decommission the Utility’s nuclear generation facilities are conducted every three yearsin conjunction with the Nuclear Decommissioning Cost Triennial Proceedings. On March 1, 2016, the Utility submitted its updated decommissioning cost estimate with the CPUC. As a result, the estimated undiscounted cost to decommission the Utility’s nuclear power plants increased by approximately $1.4 billion at March 30, 2016. The change in total estimated cost resulted in an $818 million adjustment to the ARO recognized on the Condensed Consolidated Balance Sheets. The adjustment was a result of increased estimated costs related to spent fuel storage, staffing, and out-of-state waste disposal. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered. The Utility requested that the CPUC authorize the collection of increased annual revenue requirements beginning on January 1, 2017 based on these updated cost estimates.

On June 20, 2016, the Utility entered into a joint proposalwith certain parties to retire Diablo Canyon Nuclear Power Plant at the expiration of its current operating licenses in 2024 (Unit 1) and 2025 (Unit 2), subject to certain approvals, resulting in a $115 million increase to the ARO recognized on the Condensed Consolidated Balance Sheets at June 30, 2016.

The estimated total nuclear decommissioning cost of $4.8 billion is discounted for GAAP purposes and recognized as an ARO on the Condensed Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $3.4 billion at June 30, 2016 and $2.5 billion at December 31, 2015. Changes in these estimates could materially affect the amount of the recorded ARO for these assets.

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 six months ended June 30, 2016 and 2015 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended June 30,			
(in millions)	2016	2015	2016	2015
Service cost for benefits earned	$ 113	$ 118	$ 13	$ 14
Interest cost	179	169	19	18
Expected return on plan assets	(207)	(218)	(27)	(28)
Amortization of prior service cost	2	3	4	5
Amortization of net actuarial loss	6	3	1	1
Net periodic benefit cost	93	75	10	10
Regulatory account transfer (1)	(8)	9	-	-
Total	$ 85	$ 84	$ 10	$ 10

(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	
	Six Months Ended June 30,			
(in millions)	2016	2015	2016	2015
Service cost for benefits earned	$ 226	$ 237	$ 26	$ 27
Interest cost	358	337	38	36
Expected return on plan assets	(414)	(436)	(54)	(56)
Amortization of prior service cost	4	7	8	10
Amortization of net actuarial loss	12	6	2	2
Net periodic benefit cost	186	151	20	19
Regulatory account transfer (1)	(17)	18	-	-
Total	$ 169	$ 169	$ 20	$ 19

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

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

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income (Loss)

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

	Pension Benefits	Other Benefits	Total
(in millions, net of income tax)	Three Months Ended June 30, 2016		
Beginning balance	$ (23)	$ 16	$ (7)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost			
(net of taxes of $1 and $1, respectively)	1	3	4
Amortization of net actuarial loss			
(net of taxes of $2 and $1, respectively)	4	-	4
Regulatory account transfer			
(net of taxes of $3 and $2, respectively)	(5)	(3)	(8)
Net current period other comprehensive gain (loss)	-	-	-
Ending balance	$ (23)	$ 16	$ (7)

(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	Total
	Three Months Ended June 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)	2	3	5
Amortization of net actuarial loss			
(net of taxes of $2, and $1, respectively)	1	1	2
Regulatory account transfer			
(net of taxes of $3 and $3, respectively)	(3)	(4)	(7)
Net current period other comprehensive gain (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	Total
	Six Months Ended June 30, 2016		
Beginning balance	$(23)	$ 16	$(7)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost			
(net of taxes of $2 and $3, respectively)	2	5	7
Amortization of net actuarial loss			
(net of taxes of $4 and $1, respectively)	8	1	9
Regulatory account transfer			
(net of taxes of $6 and $4, respectively)	(10)	(6)	(16)
Net current period other comprehensive gain (loss)	-	-	-
Ending balance	$(23)	$ 16	$(7)

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

(in millions, net of income tax)	Pension Benefits	Other Benefits	Other Investments	Total
	Six Months Ended June 30, 2015			
Beginning balance	$(21)	$ 15	$ 17	$ 11
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost				
(net of taxes of $3, $4, and $0, respectively) (1)	4	6	-	10
Amortization of net actuarial loss				
(net of taxes of $3, $1, and $0, respectively) (1)	3	1	-	4
Regulatory account transfer				
(net of taxes of $6, $5, and $0, respectively) (1)	(7)	(7)	-	(14)
Change in investments				
(net of taxes of $0, $0, and $12, respectively)	-	-	(17)	(17)
Net current period other comprehensive gain (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.)

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.

Recently Adopted Accounting Guidance

Fair Value Measurement

In May 2015, the FASB issued ASU No. 2015-07, Fair Value Measurement (Topic 820): 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. PG&E Corporation and the Utility adopted this guidance effectiveJanuary 1, 2016 and applied the requirements retrospectively for all periods presented. The adoption of this standard did not impact their Condensed Consolidated Financial Statements. All prior periods presented in these Condensed Consolidated financial statements reflect the retrospective adoption of this guidance (See Note 8 below.)

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. PG&E Corporation and the Utility adopted this guidance effective January 1, 2016. The adoption of this guidance did not have a material impact on their Condensed Consolidated Financial Statements.

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 the existing guidance relating to the presentation of debt issuance costs. The amendments in this ASU 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 adopted this guidance effective January 1, 2016 and applied the requirements retrospectively for all periods presented. The adoption of this guidance did not have a material impact on their Condensed Consolidated Financial Statements. PG&E Corporation and the Utility reclassified $105 million and $103 million, respectively, of debt issuance costs as of December 31, 2015 with no impact to net income or total shareholders' equity previously reported. All prior periods presented in these Condensed Consolidated Financial Statements reflect the retrospective adoption of this guidance.

Accounting Standards Issued But Not Yet Adopted

Share-based Payment Accounting

In March 2016, the FASB issued ASU No. 2016-09, Compensation – Stock Compensation (Topic 718), which amends the existing guidance relating to the accounting for share-based payment awards issued to employees, including the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2017. PG&E Corporation and the Utility will early adopt this guidance in the fourth quarter of 2016 and do not expect this ASU to have a material impact on their Condensed Consolidated Financial Statements and related disclosures.

Recognition of Lease Assets and Liabilities

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which amends the existing guidance relating to the recognition of lease assets and lease liabilities on the balance sheet and disclosing key information about leasing arrangements. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019 with retrospective application. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Condensed Consolidated Financial Statements and related disclosures.

Recognition and Measurement of Financial Assets and Financial Liabilities

In January 2016, the FASB issued ASU No. 2016-01, Financial Instruments—Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities, which amends the existing guidance relating to the recognition and measurement of financial instruments. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2018. PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Condensed Consolidated Financial Statements and related disclosures.

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which amends the existing revenue recognition guidance. In August 2015, the FASB deferred 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. (See ASU No. 2015-14, Revenue from Contracts with Customers (Topic 606): Deferral of the Effective Date.) PG&E Corporation and the Utility are currently evaluating the impact the guidance will have on their Condensed Consolidated Financial Statements and related disclosures.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets

Long-term regulatory assets are composed of the following:

	Balance at	
(in millions)	June 30, 2016	December 31, 2015
Pension benefits	$2,415	$ 2,414
Deferred income taxes	3,433	3,054
Utility retained generation	388	411
Environmental Compliance Costs	738	748
Price risk management	103	138
Unamortized loss, net of gain, on reacquired debt	85	94
Other	153	170
Total long-term regulatory assets	$7,315	$ 7,029

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2015 Form 10-K.

Regulatory Liabilities

Long-term regulatory liabilities are composed of the following:

	Balance at	
(in millions)	June 30, 2016	December 31, 2015
Cost of removal obligations	$4,832	$ 4,605
Recoveries in excess of asset retirement obligations	643	631
Public purpose programs	569	600
Other	503	485
Total long-term regulatory liabilities	$6,547	$ 6,321

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2015 Form 10-K.

Regulatory Balancing Accounts

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. These differences do not have an impact on net income. 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 comprised of the following:

	Receivable Balance at	
(in millions)	June 30, 2016	December 31, 2015

Electric distribution	$469	$ 380
Utility generation	177	122
Gas distribution	380	493
Energy procurement	40	262
Public purpose programs	151	155
Other	480	348
Total regulatory balancing accounts receivable	$1,697	$ 1,760

	Payable Balance at	
(in millions)	June 30, 2016	December 31, 2015
Energy procurement	$108	$ 112
Public purpose programs	245	244
Other	301	359
Total regulatory balancing accounts payable	$654	$ 715

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The electric distribution, utility generation, and gas distribution balancing accounts track the collection of revenue requirements approved in the GRC. Energy procurement balancing accounts track recovery of costs related to the procurement of electricity, including any environmental compliance-related activities. Public purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for commission-mandated programs such as energy efficiency and low income energy efficiency.

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 June 30, 2016:

(in millions)	Termination Date	Facility Limit		Letters of Credit Outstanding	Commercial Paper	Facility Availability
PG&E Corporation	April 2021	$300	(1)	$ -	$ -	$ 300
Utility	April 2021	3,000	(2)	33	1,280	1,687
Total revolving credit facilities		$3,300		$ 33	$ 1,280	$ 1,987

(1) Includes a $50 million lender commitment to the letter of credit sublimit 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 lender commitment to the letter of credit sublimit and a $75 million commitment for swingline loans.

In June 2016, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2020 to April 27, 2021.

Other Short-term Borrowings

In March 2016, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 2, 2017. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

Senior Notes Issuances

In March 2016, the Utility issued $600 million principal amount of 2.95% Senior Notes due March 1, 2026. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

Variable Rate Interest

At June 30, 2016, the interest rates on the $614 million principal amount of pollution control bonds Series 1996 C, E, F, and 1997 B and the related loan agreements ranged from 0.39% to 0.42%. At June 30, 2016, the interest rates on the $309 million principal amount of pollution control bonds Series 2009 A-D and the related loan agreements ranged from 0.38% to 0.44%. Pollution control bonds Series 2009 C and D will mature on December 1, 2016.

NOTE 5: EQUITY

PG&E Corporation's and the Utility's changes in equity for the six months ended June 30, 2016were as follows:

(in millions)	PG&E Corporation Total Equity	Utility Total Shareholders' Equity
Balance at December 31, 2015	$ 16,828	$ 17,060
Comprehensive income	320	318
Equity contributions	-	280
Common stock issued	299	-
Share-based compensation	35	-
Common stock dividends declared	(477)	(423)
Preferred stock dividend requirement	-	(7)
Preferred stock dividend requirement of subsidiary	(7)	-
Balance at June 30, 2016	$ 16,998	$ 17,228

During the three and six months ended June 30, 2016, PG&E Corporation sold 0.8 million and 2.2 million shares under the February 2015 equity distribution agreement for cash proceeds of $49 million and $123 million, respectively, net of commissions paid of $0.4 million and $1 million, respectively. As of June 30, 2016, the remaining gross sales available under this agreement were $301 million.

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 sixmonths ended June 30, 2016, 4 million shares were issued for cash proceeds of $165 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 June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	2016	2015	2016	2015
Income available for common shareholders	$206	$402	$313	$433
Weighted average common shares outstanding, basic	497	480	495	479
Add incremental shares from assumed conversions:				
Employee share-based compensation	1	3	2	4
Weighted average common shares outstanding, diluted	498	483	497	483
Total earnings per common share, diluted	$0.41	$0.83	$0.63	$0.90

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

Derivatives are recorded at fair value and 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.

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	June 30, 2016	December 31, 2015
Natural Gas (1) (MMBtus (2))	Forwards, Futures and Swaps	380,865,985	333,091,813
	Options	113,148,965	111,550,004
Electricity (Megawatt-hours)	Forwards, Futures and Swaps	3,852,324	3,663,512
	Congestion Revenue Rights (3)	181,803,754	216,383,389

(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 June 30, 2016, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	Gross Derivative Balance	Netting	Cash Collateral	Total Derivative Balance
Current assets – other	$106	$ (11)	$ 17	$ 112
Other noncurrent assets – other	165	(7)	-	158
Current liabilities – other	(75)	11	14	(50)
Noncurrent liabilities – other	(110)	7	3	(100)
Net commodity risk	$86	$ -	$ 34	$ 120

At December 31, 2015, the Utility's outstanding derivative balances were as follows:

	Commodity Risk			
(in millions)	Gross Derivative Balance	Netting	Cash Collateral	Total Derivative Balance
Current assets – other	$97	$ (4)	$ 25	$ 118
Other noncurrent assets – other	172	(2)	-	170
Current liabilities – other	(102)	4	44	(54)
Noncurrent liabilities – other	(140)	2	21	(117)
Net commodity risk	$27	$ -	$ 90	$ 117

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

	Commodity Risk			
	Three Months Ended		Six Months Ended	
	June 30,		June 30,	
(in millions)	2016	2015	2016	2015
Unrealized gain (loss) - regulatory assets and liabilities (1)	$66	$ 28	$59	$(24)
Realized gain (loss) - cost of electricity (2)	(12)	10	(41)	3
Realized loss - cost of natural gas (2)	(5)	(4)	(6)	(5)
Net commodity risk	$49	$ 34	$12	$(26)

(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 June 30, 2016, the Utility's credit rating was investment grade. If the Utility's credit rating were to fall below investment grade, the Utility would be required to post additional cash immediately to fully collateralize some of its net liability derivative positions.

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

	Balance at	
(in millions)	June 30, 2016	December 31, 2015
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$(11)	$ (2)
Collateral posting in the normal course of business related to		

these derivatives	7	-
Net position of derivative contracts/additional collateral posting requirements (1)	$(4)	$ (2)

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

NOTE 8: FAIR VALUE MEASUREMENTS

PG&E Corporation and the Utility measure their cash equivalents, trust assets, price risk management instruments, and other investments at fair value. A three-tier fair value hierarchy is established that prioritizes the inputs to valuation methodologies used to measure fair value:

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

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

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

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

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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 are held by PG&E Corporation and not the Utility.

	Fair Value Measurements At June 30, 2016				
(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Short-term investments	$70	$-	$-	$ -	$70
Nuclear decommissioning trusts					
Short-term investments	11	-	-	-	11
Global equity securities	1,644	-	-	-	1,644
Fixed-income securities	698	523	-	-	1,221
Assets measured at NAV	-	-	-	-	13
Total nuclear decommissioning trusts (2)	2,353	523	-	-	2,889
Price risk management instruments (Note 7)					
Electricity	21	23	215	(1)	258
Gas	1	11	-	-	12
Total price risk management instruments	22	34	215	(1)	270
Rabbi trusts					
Fixed-income securities	-	59	-	-	59
Life insurance contracts	-	74	-	-	74
Total rabbi trusts	-	133	-	-	133
Long-term disability trust					
Short-term investments	4	-	-	-	4
Assets measured at NAV	-	-	-	-	143
Total long-term disability trust	4	-	-	-	147
Total assets	$2,449	$690	$215	$ (1)	$3,509
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$26	$2	$149	$ (28)	$149
Gas	5	3	-	(7)	1
Total liabilities	$31	$5	$149	$ (35)	$150

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

(2) Represents amount before deducting $343 million, primarily related to deferred taxes on appreciation of investment value.

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	Fair Value Measurements At December 31, 2015				
(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Short-term investments	$64	$-	$-	$ -	$64
Nuclear decommissioning trusts					
Short-term investments	36	-	-	-	36
Global equity securities	1,520	-	-	-	1,520
Fixed-income securities	694	521	-	-	1,215
Assets measured at NAV	-	-	-	-	13
Total nuclear decommissioning trusts (2)	2,250	521	-	-	2,784
Price risk management instruments (Note 9 in the 2015 Form 10-K)					
Electricity	-	9	259	18	286
Gas	-	1	-	1	2
Total price risk management instruments	-	10	259	19	288
Rabbi trusts					
Fixed-income securities	-	57	-	-	57
Life insurance contracts	-	70	-	-	70
Total rabbi trusts	-	127	-	-	127
Long-term disability trust					
Short-term investments	7	-	-	-	7
Assets measured at NAV	-	-	-	-	158
Total long-term disability trust	7	-	-	-	165
Total assets	$2,321	$658	$259	$ 19	$3,428
Liabilities:					
Price risk management instruments (Note 9 in the 2015 Form 10-K)					
Electricity	$69	$1	$170	$ (70)	$170
Gas	-	2	-	(1)	1
Total liabilities	$69	$3	$170	$ (71)	$171

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

(2) Represents amount before deducting $314 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. There are no restrictions on the terms and conditions upon which the investments may be redeemed. Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the six months ended June 30, 2016 and 2015.

Trust Assets

Assets Measured at Fair Value

In general, investments held in the trusts are exposed to various risks, such as interest rate, credit, and market volatility risks. Nuclear decommissioning trust assets and other trust assets are composed primarily of equity and fixed-income securities and also include short-term investments that are money market funds valued at level 1.

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Global equity securities primarily include investments in common stock that are valued based on quoted prices in active markets and are classified as Level 1.

Fixed-income 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.

Assets Measured at NAV Using Practical Expedient

On January 1, 2016, PG&E Corporation and the Utility adopted FASB ASU No. 2015-07, Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent) and applied it retrospectively for the periods presented in their Condensed Consolidated Financial Statements. (See Note 2 above.) In accordance with this guidance, investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Condensed Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

Price Risk Management Instruments

Price risk management instruments include physical and financial derivative contracts, such as power purchase agreements, forwards, futures, 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 futures 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 futures, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded options are valued using observable market data and market-corroborated data and are classified as Level 2.

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

The Utility holds CRRs to hedge the financial risk of CAISO-imposed congestion charges in the day-ahead market. Limited market data is available in the CAISO auction and between auction dates; therefore, the Utility utilizes historical prices to forecast forward prices. CRRs are classified as Level 3.

Level 3 Measurements and Sensitivity Analysis

The Utility's market and credit risk management function, which reports to the Chief Risk and Audit 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.)

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(in millions)	Fair Value at At June 30, 2016		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	Input	Range (1)
Congestion revenue rights	$215	$ 53	Market approach	CRR auction prices	$(23.81) - 103.97
Power purchase agreements	$-	$ 96	Discounted cash flow	Forward prices	$18.07 - 38.80

(1) Represents price per megawatt-hour

(in millions)	Fair Value at At December 31, 2015		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	Input	Range (1)
Congestion revenue rights	$259	$ 63	Market approach	CRR auction prices	$(161.36) - 8.76
Power purchase agreements	$-	$ 107	Discounted cash flow	Forward prices	$15.08 - 37.27

(1) Represents price per megawatt-hour

Level 3 Reconciliation

The following tables present the reconciliation for Level 3 price risk management instruments for the three and six months ended June 30, 2016 and 2015:

	Price Risk Management Instruments	
(in millions)	2016	2015
Asset (liability) balance as of April 1	$ 75	$ 42
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(9)	6
Asset (liability) balance as of June 30	$ 66	$ 48

(1) The costs related to price risk management activities are fully passed through to customers in rates. Accordingly, unrealized gains and losses are deferred in regulatory liabilities and assets and net income is not impacted.

Price Risk
Management

	Instruments	
(in millions)	2016	2015
Asset (liability) balance as of January 1	$ 89	$ 69
Net realized and unrealized gains:		
Included in regulatory assets and liabilities or balancing accounts (1)	(23)	(21)
Asset (liability) balance as of June 30	$ 66	$ 48

(1) The costs related to price risk management activities are fully passed through to customers in rates. Accordingly, unrealized gains and losses are deferred in regulatory liabilities and assets and net income is not impacted.

Financial Instruments

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

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at June 30, 2016 and December 31, 2015, as they are short-term in nature or have interest rates that reset daily.

- The fair values of the Utility's fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation's fixed-rate senior notes were based on quoted market prices at June 30, 2016 and December 31, 2015.

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

	At June 30, 2016		At December 31, 2015	
(in millions)	Carrying Amount	Level 2 Fair Value	Carrying Amount	Level 2 Fair Value
PG&E Corporation	$350	$357	$350	$354
Utility	15,415	18,356	14,918	16,422

Available for Sale Investments

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

(in millions)	Amortized Cost	Total Unrealized Gains	Total Unrealized Losses	Total Fair Value
As of June 30, 2016				
Nuclear decommissioning trusts				
Short-term investments	$ 11	$-	$-	$11
Global equity securities	621	1,051	(15)	1,657
Fixed-income securities	1,126	98	(3)	1,221
Total (1)	$ 1,758	$1,149	$(18)	$2,889
As of December 31, 2015				
Nuclear decommissioning trusts				
Short-term investments	$ 36	$-	$-	$36
Global equity securities	508	1,034	(9)	1,533
Fixed-income securities	1,165	58	(8)	1,215
Total (1)	$ 1,709	$1,092	$(17)	$2,784

(1) Represents amounts before deducting $343 million and $314 million at June 30, 2016 and December 31, 2015, respectively, primarily related to deferred taxes on appreciation of investment value.

The fair value of fixed-income securities by contractual maturity is as follows:

As of

(in millions)	June 30, 2016
Less than 1 year	$35
1–5 years	408
5–10 years	262
More than 10 years	516
Total maturities of fixed-income securities	$1,221

The following table provides a summary of activity for the investments:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2016	2015	2016	2015
(in millions)				
Proceeds from sales and maturities of nuclear decommissioning trust investments	$282	$362	$721	$779
Gross realized gains on securities held as available-for-sale	4	12	9	47
Gross realized losses on securities held as available-for-sale	(1)	(10)	(3)	(13)

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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. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's policy is to exclude anticipated legal costs from the provision for loss and expense these costs as incurred.

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

Order Instituting an Investigation into Compliance with Ex Parte Communication Rules

During 2014 and 2015, the Utility filed several reports to notify the CPUC of communications that the Utility believes may have constituted or described ex parte communications that either should not have been made or that should have been timely reported to the CPUC. Ex parte communications include communications between a decision maker or a Commissioner's advisor and interested persons concerning substantive issues in certain formal proceedings. Certain communications are prohibited and others are permissible with proper noticing and reporting.

On November 23, 2015, the CPUC issued an OII into whether the Utility should be sanctioned for violating rules pertaining to ex parte communications and Rule 1.1 of the CPUC's Rules of Practice and Procedure governing the conduct of those appearing before the CPUC. The OII cites some of the communications the Utility reported to the CPUC. The OII also cites the ex parte violations alleged in the City of San Bruno's July 2014 motion, which it filed in the CPUC investigations related to the Utility's natural gas transmission pipeline operations and practices.

On July 12, 2016, the assigned commissioner and ALJ adopted the process report jointly submitted by the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility in April 2016. The approved framework for resolving the proceeding includes a total of 159 communications (the 46 communications already included in the OII and 113 additional communications) in the scope of the proceeding, a procedure for moving undisputed facts into the evidentiary record and a diligence process for providing additional factual information. The Utility and the other parties disagreed on the inclusion of an additional 21 communications in the scope and filed briefs on the issue. The ruling does not currently include these communications within the scope of the proceeding but leaves the matter open for review pending the parties' discovery on these communications.

The CPUC will determine whether the communications included within the scope of the proceeding were in violation of its rules and whether to impose penalties or other remedies. The CPUC can impose fines up to $50,000 for each violation, per day. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as how many days each violation continued; 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 discretion in determining penalties.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the OII but they are unable to reasonably estimate the amount or range of future charges that could be incurred, because it is uncertain how the CPUC will calculate the number of violations or the penalty for any violations.

Finally, the U.S. Attorney's Office in San Francisco and the California Attorney General's office also have been investigating matters related to allegedly improper communication between the Utility and CPUC personnel. 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 required 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 cited 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.

On June 1, 2016, the assigned ALJ issued a POD in the CPUC's investigation. The POD finds that the Utility failed to comply with applicable laws and regulations in maintaining accurate records of its natural gas distribution system and assesses a penalty of $24 million. With the citation previously assessed for the Carmel incident, the total fine imposed on the Utility is $35 million. The POD determines that certain incidents show systemic failure on the Utility's part, while other incidents are isolated deviations in an otherwise generally compliant system. The identified systemic failures are as follows: (1) failure to promptly and comprehensively correct mapping errors of plastic inserts in the distribution system, (2) failure to promptly and comprehensively analyze the impacts of the missing paper leak repair records from 1979 to 1991 for the De Anza division, and to institute such corrective actions as may be possible, and (3) failure to adequately respond to local officials. The POD also identifies 13 operational incidents defined as isolated violations.

The POD does not order remedial measures. Instead, the Utility and all interested parties are to meet and confer to consider and develop additional remedial measures necessary to address the issues identified in the POD. The objective of this process will be a comprehensive compliance plan that includes all feasible and cost-effective measures necessary to improve the Utility's natural gas distribution facilities record-keeping. The POD indicates that the SED shall participate in and monitor this process and, no later than 120 days after the effective date of the order, the Utility shall submit its initial compliance plan.

On June 28, 2016 and July 1, 2016, the City of Carmel-by-the-Sea ("Carmel") and the SED, respectively, filed an appeal from the POD. In its appeal, the SED indicates that the $24 million fine assessed in the POD is insufficient and recommends that its initial penalty recommendation of $112 million be adopted. If the recommended penalty is not adopted, the SED recommends modifications to the POD, including both method and scope changes to the penalty calculation, that would result in a shareholder-funded fine of $55.5 million. With the citation previously assessed for the Carmel incident, the total fines imposed on the Utility would amount to $66 million. Specifically, if the SED's initial recommendation of $112 million is not adopted, the SED recommends edits to the POD proposing that (1) the POD should remove all language that suggests that 99 percent safety is acceptable, (2) the Utility should be ordered to pay a shareholder-funded fine in connection with the maximum allowable operating pressure documentation, (3) a different violation end date should be used for the missing DeAnza leak repair records, and (4) the POD's methodology for assessing fines for specific incidents should be adjusted. Carmel indicates that the POD incorrectly applied fines corresponding to the violations it found the Utility committed and requests that the CPUC imposes a just fine and proper remedies to promote deterrence. Carmel also indicates that the POD erred by not offering discussions on whether the shareholders or customers should bear the cost of the fine and on Carmel's proposed remedies.

On July 18, 2016, the Utility filed its response to these appeals. The Utility cannot predict when the CPUC will issue a decision or its outcome.

At June 30, 2016, the Utility's Condensed Consolidated Balance Sheets include a $24 million accrual in connection with the POD. It is reasonably possible that the Utility will incur a loss in excess of this amount, as the CPUC may impose a higher fine and other penalties, as a result of the appeals currently pending in this proceeding. PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows could be materially affected depending on the ultimate amount of the penalty that is imposed and the ultimate amount of unrecoverable costs that the Utility incurs to comply with required remedial measures.

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 had been completed and that remediation work, including removal of the encroachments, was 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 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. In addition, the California utilities are required to inform the SED of self-identified or self-corrected violations of natural gas safety regulations. The CPUC has delegated authority to the SED to issue citations and impose fines for violations identified through audits, investigations, or self-reports. The SED can consider the discretionary factors discussed above (see "Order Instituting an Investigation into Compliance with Ex Parte Communication Rules" above) in determining the number of violations and whether to impose daily fines for continuing violations. The SED is required, however, to impose the maximum statutory penalty of $50,000 for each separate violation.

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 superseded 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. On December 23, 2015, the court presiding over the federal criminal proceeding dismissed 15 of the Pipeline Safety Act counts, leaving 13 remaining counts. The trial began on June 14, 2016. On July 26, 2016, the court granted the government's motion to dismiss Count 13 alleging that the Utility knowingly and willfully failed to retain strength pressure test record with respect to a distribution feeder main (DFM1816-01). Therefore, the number of counts has been reduced from 13 to 12. On July 27, 2016, the parties completed delivering their closing arguments and the case was submitted to the jury. The Utility is unable to predict when and if the jury will return its verdict.

The maximum statutory fine for each felony count is $500,000, for total potential fines of $6 million. The government is also seeking fines under the Alternative Fines Act. The Alternative Fines Act 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." On December 8, 2015, the court issued an order granting, in part, the Utility's request to dismiss the government's allegations seeking an alternative fine under the Alternative Fines Act. The court dismissed the government's allegations regarding the amount of losses, but concluded that it required additional information about how the government would prove its allegations about the amount of gross gains prior to deciding whether to dismiss those allegations. Based on the superseding indictment's allegation that the Utility derived gross gains of approximately $281 million, the potential maximum alternative fine would be approximately $562 million. On February 2, 2016, the court issued an order holding that if the government's allegations about the Utility's gross gains are considered, they would be considered in a second trial phase that would take place after the trial on the criminal charges.

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. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Condensed Consolidated Financial Statements as such amounts were not considered to be probable.

Other Federal Matters

The Utility was informed that the U.S. Attorney’s Office is 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 relating to the criminal indictment discussed above. It is uncertain whether any additional charges will be brought against the Utility.

Disallowance of Plant Costs

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates and the amount of disallowance can be reasonably estimated. Capital disallowances are reflected in operating and maintenance expenses in the Condensed Consolidated Statements of Income. Disallowances as a result of the CPUC’s June 23, 2016 final phase one decision in the Utility’s 2015 GT&S rate case and the April 9, 2015 Penalty Decision are discussed below.

2015 GT&S Rate Case Disallowance of Capital Expenditures

On June 23, 2016, the CPUC approved a final decision in phase one of the Utility’s 2015 GT&S rate case. The decision permanently disallowed 2011 through 2014 capital spending in excess of the amount adopted and established various cost caps that will increase the risk of overspend over the current rate case cycle, including new one-way capital balancing accounts. As a result, during the three and six months ended June 30, 2016, the Utility incurred charges of $190 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This includes $134 million to the net plant balance for 2011 through 2014 capital expenditures in excess of adopted amounts and $56 million for the Utility’s estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts.

Penalty Decision’s Disallowance of Natural Gas Capital Expenditures

On April 9, 2015, the CPUC issued a decision in its investigative enforcement proceedings pending against the Utility to impose total penalties of $1.6 billion on the Utility after determining that the Utility had committed numerous violations of laws and regulations related to its natural gas transmission operations (the "Penalty Decision"). In January 2016, the CPUC closed the investigative proceedings. The total penalty includes (1) a $300 million fine, (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.

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For the three and six months ended June 30, 2016, the Utility recorded charges for disallowed capital spending of $148 million and $235 million, respectively, as a result of the Penalty Decision. The cumulative charges at June 30, 2016, and the additional future charges to reach the $1.6 billion total are shown in the following table:

(in millions)	Six Months Ended June 30, 2016	Cumulative Charges June 30, 2016	Future Charges and Costs	Total Amount
Fine paid to the state	$-	$ 300	$ -	$ 300
Customer bill credit paid	-	400	-	400
Charge for disallowed capital (1)	235	642	50	692
Disallowed revenue for pipeline safety expenses (2)	-	-	158	158
CPUC estimated cost of other remedies (3)	-	-	-	50
Total Penalty Decision fines and remedies	$235	$ 1,342	$ 208	$ 1,600

(1) The Penalty Decision disallows the Utility from recovering $850 million in costs associated with pipeline safety-related projects and programs that the CPUC will identify in a final phase two decision to be issued in the Utility's 2015 GT&S rate case. The CPUC recommended in its May 5, 2016 proposed decision in the Utility's 2015 GT&S rate case that at least $692 million of the $850 million cost disallowance be allocated to capital expenditures. (In the final phase one decision, the CPUC requested comments on whether the percentage of the disallowance that should be applied to capital expenditures as opposed to expense should be changed.) The Utility estimates that approximately $642 million of cumulative capital spending is probable of disallowance, subject to adjustment based on the CPUC final phase two decision in the Utility's 2015 GT&S rate case.

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

(3) In the Penalty Decision, the CPUC estimated that the Utility would incur $50 million to comply with the remedies specified in the Penalty Decision. This table does not reflect the Utility's remedy-related costs already incurred nor the Utility's estimated future remedy-related costs. These costs would be expensed as incurred.

Capital Expenditures Relating to Pipeline Safety Enhancement Plan

The CPUC has authorized the Utility to collect $766 million for recovery of PSEP capital costs. As of June 30, 2016, the Utility has spent $1.3 billion on PSEP-related capital costs, of which $665 million was expensed in previous years for costs that are expected to exceed the authorized amount. The Utility expects the remaining PSEP work to continue beyond 2016. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

Butte Fire Litigation

On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the “Butte fire,” the wildfire that ignited and spread in Amador and Calaveras Counties in Northern California in September 2015. Cal Fire’s report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility’s electric line which ignited portions of the tree, and determined that the failure by the Utility and its vegetation management contractors to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. Approximately 44 complaints have been filed to date against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving approximately 1,550 individual plaintiffs and their insurance companies. These complaints are now part of the master complaints. The number of individual complaints and plaintiffs may increase in the future.

Plaintiffs have begun to present to the Utility claims seeking early resolution of preference cases (individuals who due to their age and/or physical condition are not likely to meaningfully participate in a trial under normal scheduling). The Utility has begun mediating and settling these preference cases. A case management conference was held on July 14, 2016 and the next case management conference is scheduled for September 1, 2016.

In connection with this matter, the Utility may be liable for property damages without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent.

Based on the evidence described in the Cal Fire report that the Gray Pine tree contacted an electric line of the Utility, the Utility believes that it is probable that it will incur a loss of $350 million for property damages in connection with this matter, which corresponds to the lower end of the range of its reasonably estimable losses. This amount is based on estimates about the number, size, and type of structures damaged or destroyed, and assumptions about the contents of such structures and other property damage. The Utility currently is unable to reasonably estimate the upper end of the rangebecause it is at an early stage of the evaluation of claims and the mediation and settlement process. At June 30, 2016, the Condensed Consolidated Balance Sheets include $350 million in other current liabilities for the estimated property damages.

The Utility also believes that it is reasonably possible that it will incur a loss in excess of the $350 million accrued through June 30, 2016, for additional costs related to fire suppression, personal injury damages, and other damages. The Utility believes that $90 million is a reasonable estimate of fire suppression costs. The Utility currently is unable to reasonably estimate other costs for the reasons indicated above.

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. At June 30, 2016, the Utility recorded $260 million for probable insurance recoveries in connection with recovery of losses related to the Butte fire, included in Other accounts receivable in the Condensed Consolidated Balance Sheets. The Utility plans to seek full recovery of all insured losses and while the Utility believes that a significant portion of costs incurred for third-party claims (and associated legal expenses) relating to Butte fire will ultimately be recovered through its insurance, it is unable to predict the amount and timing of such insurance recoveries. 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, results of operations, or cash flows could be materially affected.

Other Contingencies

PG&E Corporation and the Utility are subject to various claims, lawsuits and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters" and "Butte Fire Litigation") totaled $69 million at June 30, 2016 and $63 million at December 31, 2015. These amounts are included in other current liabilities in the Condensed Consolidated Balance Sheets. At June 30, 2016, it is reasonably possible that the accrual could increase by $30 million. The resolution of these matters is not expected to have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows.

Environmental Remediation Contingencies

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

	Balance at	
(in millions)	June 30, 2016	December 31, 2015
Topock natural gas compressor station (1)	$302	$ 300
Hinkley natural gas compressor station (1)	138	140
Former manufactured gas plant sites owned by the Utility or third parties	305	271
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites	148	164
Fossil fuel-fired generation facilities and sites	103	94
Total environmental remediation liability	$996	$ 969

(1) See “Natural Gas Compressor Station Sites” below.

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At June 30, 2016, the Utility expected to recover $711 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 subject to the regulatory authority of the Regional Board. On November 4, 2015, the Regional Board adopted a final clean-up and abatement order to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order requires setting plume capture requirements, requires establishing a monitoring and reporting program, and finalizes deadlines for the Utility to meet interim cleanup targets.

The Utility's environmental remediation liability at June 30, 2016 reflects the Utility's best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final remediation plan and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the DTSC and the DOI. In November 2015, the Utility submitted its final remediation design to the agencies for approval. The

Utility's design 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 design, and the Utility anticipates that the DTSC's draft environmental impact report will be issued for public comment in late 2016. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in early 2017. After the Utility modifies its design in response to the final report, the Utility will seek approval to begin construction of the new in-situ treatment system in late 2017.

The Utility's environmental remediation liability at June 30, 2016 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

Reasonably Possible Environmental Contingencies

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $2.0 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, future financial condition, and cash flows during the period in which they are recorded.

Nuclear Insurance

In addition to the nuclear insurance the Utility maintains through the NEIL, the Utility also is a member of the EMANI, which provides excess insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear or non- nuclear event were to occur at Diablo Canyon.

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, the current maximum aggregate annual retrospective premium obligation for the Utility is approximately $60 million. EMANI provides $200 million for any one accident and in the annual aggregate excess of the combined amount recoverable under the Utility’s NEIL policies. If EMANI losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $2.1 million. For more information about the Utility’s NEIL coverage, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2015 Form 10-K.

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

At December 31, 2015, the Consolidated Balance Sheets reflected $454 million in net claims, within Disputed claims and customer refunds, and $228 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 six months ended June 30, 2016. However, on June 27, 2016, the FERC approved the Utility’sjoint offer of settlement which includes a $256 million settlement agreementand any related adjustments. If approved by the respective bankruptcy courts for the Utility and the California Power Exchange, the settlement agreement would not result in a refund to customers or an impact to net income. The settlement agreement would result in a reduction to the Utility’s net disputed claims liability and a reduction to both the receivable in regulatory assets and the remaining escrow balance.

Tax Matters

PG&E Corporation’s and the Utility’s unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of June 30, 2016, it is reasonably possible that unrecognized tax benefits will decrease by approximately $60 million within the next 12 months. PG&E Corporation and the Utility believe that the majority of the decrease will not impact net income.

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, 2015 the Utility had undiscounted future expected obligations of approximately $50 billion. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2015 Form 10-K.) The Utility has not entered into any new material commitments during the six months ended June 30, 2016.

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 is alsosubject 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 2015 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, including certain pipeline related expenses, certain legal and regulatory related expenses, fines and penalties, Butte fire related costs, and impacts of the 2015 GT&S rate case. 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 planning, 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.

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions, except per share amounts)	Earnings (1)	EPS (Diluted)	Earnings (1)	EPS (Diluted)
Income Available for Common Shareholders - June 30, 2015	$402	$ 0.83	$433	$ 0.90
Fines and penalties (2)	44	0.09	413	0.85
Pipeline-related expenses (3)	9	0.02	19	0.04
Legal and regulatory related expenses (4)	10	0.02	18	0.04
Natural gas matters insurance recoveries	(23)	(0.05)	(23)	(0.05)
Earnings from Operations - June 30, 2015 (5)	$442	$ 0.91	$860	$ 1.78
Growth in rate base earnings	25	0.05	51	0.10
Timing of taxes (6)	(41)	(0.08)	(81)	(0.16)
Nuclear refueling outage	(30)	(0.06)	(30)	(0.06)
Regulatory and legal matters	(23)	(0.05)	(23)	(0.05)
Gain on disposition of SolarCity stock (7)	-	-	(14)	(0.03)
Increase in shares outstanding	-	(0.03)	-	(0.05)
Miscellaneous	(43)	(0.08)	(26)	(0.05)
Earnings from Operations - June 30, 2016 (5)	$330	$ 0.66	$737	$ 1.48
Butte fire related costs (net of insurance) (8)	125	0.25	(101)	(0.20)
Fines and penalties (2)	(112)	(0.22)	(163)	(0.32)
Pipeline-related expenses (3)	(16)	(0.03)	(29)	(0.06)
Legal and regulatory related expenses (4)	(8)	(0.02)	(18)	(0.04)

GT&S capital disallowance (9)	(113)	(0.23)	(113)	(0.23)
Income Available for Common Shareholders - June 30, 2016	$206	$ 0.41	$313	$ 0.63

(1) All amounts presented in the table above are tax-adjusted at PG&E Corporation's combined statutory tax rate of 40.75%, unless otherwise noted.

(2) Represents the impact of the Penalty Decision (see Note 9 of the Notes to the Condensed Consolidated Financial Statements). For the three and six months ended June 30, 2016, the Utility incurred costs of $148 million pre-tax (before tax impact of $60 million) and $235 million pre-tax (before tax impact of $96 million), respectively for disallowed capital charges. In addition, for the three and six months ended June 30, 2016, the Utility accrued fines of $24 million, which are not deductible for tax purposes, in connection with the POD in the CPUC's investigation regarding natural gas distribution facilities record-keeping practices.

(3) The Utility incurred costs of $27 million pre-tax (before tax impact of $11 million) and $49 million pre-tax (before tax impact of $20 million), during the three and six months ended June 30, 2016, respectively, for pipeline related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights of way.

(4) The Utility incurred costs of $14 million pre-tax (before tax impact of $6 million) and $31 million pre-tax (before tax impact of $13 million), during the three and six months ended June 30, 2016, respectively, for legal and regulatory related expenses incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(5) "Earnings from operations" is not calculated in accordance with GAAP and excludes the items impacting comparability shown in Notes (2), (3), (4), (8) and (9).

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

(7) Represents the gain recognized during the six months ended June 30, 2015. No comparable gain was recognized in 2016.

(8) The Utility accrued charges of $0 million and $350 million pre-tax (before tax impact of $143 million), for the three and six months ended June 30, 2016, respectively, related to estimated property damages in connection with the Butte fire, partially offset by approximately $260 million pre-tax (before tax impact of $106 million) accrued as probable insurance recoveries. The Utility also incurred charges of $49 million pre-tax (before tax impact of $20 million) and $80 million pre-tax (before tax impact of $32 million), for the three and six months ended June 30, 2016, respectively, for Utility clean-up, repair, and legal costs associated with the Butte fire.

(9) Represents charges of $190 million pre-tax (before tax impact of $77 million) of probablecapitaldisallowancesas a result of thephase one 2015 GT&S rate case decision that the Utility incurred in the three and six months ended June 30, 2016, including $134 million pre-tax (before tax impact of $54 million) for 2011 through 2014 capital expenditures in excess of adopted amounts and $56 million pre-tax (before tax impact of $23 million) for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. (See "Regulatory Matters" below for more information.)

Key Factors Affecting Financial Results

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

- The Outcome of Enforcement, Litigation, and Regulatory Matters. Future financial results will be impacted by the unrecoverable pipeline safety-related and remedies costs required by the Penalty Decision. (For more information about the Penalty Decision, see Note 9 of the Notes to the Condensed Consolidated Financial Statements.) The Utility's future results may also be impacted by various other pending enforcement, litigation and regulatory actions, including but not limited to those related to the federal criminal charges and CPUC investigations of the Utility's compliance with natural gas distribution facilities record-keeping practices, potential violations of the CPUC's ex parte communication rules, and the Butte fire. (See Note 9 of the Notes to the Condensed Consolidated Financial

Statements in Item 1.)

- The Timing and Outcome of Ratemaking Proceedings. The CPUC approved 2015 GT&S "interim" revenue requirements in its phase one decision dated June 23, 2016. The authorized revenue requirements are effective retroactive to January 1, 2015. However, the Utility will not be able to record the revenue requirement increase since January 1, 2015 until after the final phase two decision is issued. The final phase two decision will allocate the $850 million of shareholder funded safety work related to the Penalty Decision and as a result, reduce revenue requirements in this rate case. (See "Regulatory Matters – 2015 Gas Transmission and Storage Rate Case" below for more information.) Additionally, in May 2016, the Utility updated its 2017 GRC application to request that the CPUC authorize a revenue requirement increase of $319 million for 2017 for the Utility's electric generation business and its electric and natural gas distribution businesses with attrition increases in 2018 and 2019. In order to allow settlement discussions to proceed, the procedural schedule for this case has been updated calling for a final decision in early 2017, if a settlement has not been reached before then. A settlement conference is currently scheduled for August 3, 2016. (See "Regulatory Matters – 2017 General Rate Case" below for more information.) The outcome of regulatory 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 and Recover Operating Costs and Capital Expenditures. The Utility's ability to earn its authorized rate of return could be materially affected if actual costs differ from the amounts authorized in the rate case decisions. In addition to incurring shareholder-funded safety costs and costs associated with remedial measures required by the Penalty Decision, the Utility also forecasts that in 2016 it will incur unrecovered pipeline-related expenses ranging from $100 million to $150 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. Also, the June 23, 2016 phase one CPUC decision in the Utility's 2015 GT&S rate case establishes various cost caps that will increase the risk of overspend over the current rate case cycle. The ultimate amount of unrecovered costs also 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 Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.) The Utility's ability to recover costs in the future also could be affected by decreases in customer demand. (See "Forward-Looking Statements" below for more information.)

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- The Amount and Timing of the Utility's Financing Needs. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. For the six months ended June 30, 2016, PG&E Corporation issued $299 million of common stock and used $280 million of the cash proceeds to make equity contributions to the Utility. 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 charges incurred by the Utility to comply with the Penalty Decision, to fund unrecoverable pipeline-related expenses, and to pay fines and penalties that may be required by the final outcomes of pending enforcement matters. These additional issuances would have a material dilutive impact 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 Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1, Financial Statements and Supplementary Data, changes in their respective credit ratings, general economic and market conditions, and other factors.

For more information about the factors and risks that could affect future results of operations, financial condition, and cash flows, or that could cause future results to differ from historical results, see "Item 1A. Risk Factors"in the 2015 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 "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 six months ended June 30, 2016 and 2015:

	Three Months Ended June 30,		Six Months Ended June 30,	
(in millions)	2016	2015	2016	2015
Consolidated Total	$ 206	$ 402	$ 313	$ 433
PG&E Corporation	1	-	3	30
Utility	$ 205	$ 402	$ 310	$ 403

PG&E Corporation’s net income primarily consists of interest expense on long-term debt, income taxes, and other income from investments. Results for the six months ended June 30, 2015 include approximately $30 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation with no corresponding gains for the same period in 2016.

Utility

The tables below shows certain items from the Utility’s Condensed Consolidated Statements of Income for the three and six months ended June 30, 2016 and 2015. 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.

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The Utility's operating results for the three and six months ended June 30, 2016 and 2015 reflect charges associated with the impact of the Penalty Decision. (See "Utility Revenues and Costs that Impacted Earnings" below.)

	Three Months Ended June 30, 2016 Revenues/Costs:			Three Months Ended June 30, 2015 Revenues/Costs:		
(in millions)	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$1,993	$ 1,472	$3,465	$1,877	$ 1,585	$3,462
Natural gas operating revenues	525	179	704	526	228	754
Total operating revenues	2,518	1,651	4,169	2,403	1,813	4,216
Cost of electricity	-	1,156	1,156	-	1,277	1,277
Cost of natural gas	-	75	75	-	118	118
Operating and maintenance	1,417	420	1,837	1,065	418	1,483
Depreciation, amortization, and decommissioning	700	-	700	651	-	651
Total operating expenses	2,117	1,651	3,768	1,716	1,813	3,529
Operating income	401	-	401	687	-	687
Interest income (1)			4			3
Interest expense (1)			(204)			(189)
Other income, net (1)			21			20
Income before income taxes			222			521
Income tax provision (1)			13			115
Net income			209			406
Preferred stock dividend requirement (1)			4			4
Income Available for Common Stock			$205			$402

(1) These items impacted earnings for the three months ended June 30, 2016 and 2015.

	Six Months Ended June 30, 2016 Revenues/Costs:			Six Months Ended June 30, 2015 Revenues/Costs:		
(in millions)	That Impacted Earnings	That Did Not Impact Earnings	Total Utility	That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$3,910	$ 2,687	$6,597	$3,662	$ 2,814	$6,476
Natural gas operating revenues	1,048	499	1,547	1,031	609	1,640
Total operating revenues	4,958	3,186	8,144	4,693	3,423	8,116

Cost of electricity	-	2,106	2,106	-	2,277	2,277
Cost of natural gas	-	297	297	-	392	392
Operating and maintenance	3,065	783	3,848	2,652	754	3,406
Depreciation, amortization, and decommissioning	1,396	-	1,396	1,282	-	1,282
Total operating expenses	4,461	3,186	7,647	3,934	3,423	7,357
Operating income	497	-	497	759	-	759
Interest income (1)			8			4
Interest expense (1)			(405)			(376)
Other income, net (1)			45			46
Income before income taxes			145			433
Income tax (benefit) provision (1)			(172)			23
Net income			317			410
Preferred stock dividend requirement (1)			7			7
Income Available for Common Stock			$310			$403

(1) These items impacted earnings for the six months ended June 30, 2016 and 2015.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for the three and six months ended June 30, 2016 and 2015, focusing on revenues and expenses that impacted earnings for these periods.

The Utility has received a final phase one decision in its 2015 GT&S rate case. However, the Utility will not be able to recognize the full impact until the CPUC issues a final phase two decision in this rate case. Any revenue requirement increase the CPUC may authorize in the GT&S rate case would be retroactive to January 1, 2015. In addition, accounting rules preclude the Utility from recording the full amount of the revenue requirement increase until 2017.(See "Regulatory Matters" below.)

Operating Revenues

The Utility's electric and natural gas operating revenues that impacted earnings increased by $115 million, or 5%, and by $265 million, or 6%, in the three and six months ended June 30, 2016, compared to the same periods in 2015 primarily due to additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO rate case. (See "Regulatory Matters" below.)

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased by $352 million, or 33%, in the three months ended June 30, 2016 compared to the same period in 2015 primarily due to $190 million in permanently disallowed capital spending in the final phase one 2015 GT&S rate case decision (see "Regulatory Matters" below), $73 million of higher disallowed capital charges related to the Penalty Decision, $50 million in costs related to a scheduled nuclear refueling outage at Diablo Canyon that occurred during the three months ended June 30, 2016, $49 million in charges related to the Butte fire, a $24 million charge recorded in connection with the POD related to the natural gas distribution facilities record-keeping investigation, and other expenses related to timing differences. These increases were partially offset by approximately $260 million in probable insurance recoveries related to the Butte fire recorded in the three months ended June 30, 2016 with no corresponding activity for the same period in 2015. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

The Utility's operating and maintenance expenses that impacted earnings increased by $413 million, or 16%, in the six months ended June 30, 2016 compared to the same period in 2015 primarily due to $430 million in charges related to the Butte fire, $190 million in permanently disallowed capital spending in the final phase one 2015 GT&S rate case decision (see “Regulatory Matters” below), $107 million of higher disallowed capital charges related to the Penalty Decision, $50 million in costs related to a scheduled nuclear refueling outage at Diablo Canyon that occurred during the three months ended June 30, 2016, a $24 million charge recorded in connection with the POD related to the natural gas distribution facilities record-keeping investigation, and other expenses related to timing differences. These increases were partially offset by $500 million in charges associated with the Penalty Decision for fines and customer refunds incurred in the first six months of 2015 with no corresponding charges in 2016. Additionally, the Utility recorded approximately $260 million in probable insurance recoveries related to the Butte fire in the three months ended June 30, 2016 with no corresponding activity for the same period in 2015. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements.)

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

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Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by $49 million, or 8%, and by $114 million, or 9%, in the three and six months ended June 30, 2016 compared to the same periods in 2015. These increases were primarily due to the impact of capital additions as authorized by the CPUC in the 2014 GRC decision as well as higher capital additions and higher depreciation rates as authorized by the FERC in the TO rate case.

Interest Expense

The Utility's interest expense increased by $15 million, or 8%, and by $29 million, or 8%, in the three and six months ended June 30, 2016 compared to the same periods in 2015. These increases were primarily driven by higher levels of long term debt and short term borrowings in 2016 compared to the same periods in 2015.

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 $102 million and $195 million in the three and six months ended June 30, 2016 as compared to the same periods in 2015. The following describes the change in the Utility's effective tax rate for the three and six months ended June 30, 2016 as compared to the same periods in 2015:

- The effective tax rates for the three months ended June 30, 2016 and 2015 were 6% and 22%, respectively. The decrease in the effective tax rate was primarily due to higher benefits resulting from various property-related tax deductions recorded during the three months ended June 30, 2016 with lower comparable amounts in the three month period ending June 30, 2015.
- The effective tax rates for the six months ended June 30, 2016 and 2015 were (119)% and 5%, respectively. The decrease in the effective tax rate was primarily due to higher benefits resulting from various property-related tax deductions recorded during the six months ended June 30, 2016 with lower comparable amounts in the six month period ending June 30, 2015, as well as benefits resulting from various tax audit

results recorded during the six months ended June 30, 2016 with no comparable amounts in the six month period ending June 30, 2015.

Utility Revenues and Costs that did not Impact Earnings

Fluctuations in revenues that did not impact earnings are primarily driven by electricity and natural gas procurement costs. See below for more information.

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Cost of Electricity

The Utility'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 June 30,		Six Months Ended June 30,	
(in millions)	2016	2015	2016	2015
Cost of purchased power	$1,113	$1,207	$1,999	$2,129
Fuel used in own generation facilities	43	70	107	148
Total cost of electricity	$1,156	$1,277	$2,106	$2,277
Average cost of purchased power per kWh (1)	$0.099	$0.103	$0.101	$0.101
Total purchased power (in millions of kWh) (2)	11,228	11,747	19,767	21,038

(1)Average cost of purchased power for the three and six months ended June 30, 2016 remained relatively flat compared to the same periods in 2015. A higher percentage of renewable energy resources were offset by lower market prices for natural gas.

(2) The decrease in purchased power for the three and six months ended June 30, 2016 resulted from an increase year-to-date in generation from the Utility's own generation facilities and lower electric customer demand. Hydroelectric generation increased during the three and six months ended June 30, 2016 as compared to the same periods in 2015.

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.

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.

(in millions)	Three Months Ended June 30, 2016	2015	Six Months Ended June 30, 2016	2015
Cost of natural gas sold	$44	$83	$225	$317
Transportation cost of natural gas sold	31	35	72	75
Total cost of natural gas	$75	$118	$297	$392
Average cost per Mcf (1) of natural gas sold (2)	$1.16	$2.18	$1.91	$2.88
Total natural gas sold (in millions of Mcf) (1)	38	38	118	110

(1) One thousand cubic feet
(2) Average cost of natural gas sold primarily impacted by a decline in the market price of natural gas in the three and six months ended June 30, 2016 compared to the same periods in 2015.

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 on 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 cost of capital. 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 issuances and repayments under its revolving credit facility and commercial paper program. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation forecasts that it will issue approximately $800 million in common stock during 2016, primarily to fund equity contributions to the Utility. The Utility's equity needs will continue to be affected by charges incurred to comply with the Penalty Decision, by the timing and outcome of the final phase two decision in the 2015 GT&S rate case, by unrecoverable pipeline-related expenses, and by fines and penalties that may be imposed in connection with the matters 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 that were filed in the Utility's reorganization proceedings 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

During the three and six months ended June 30, 2016, PG&E Corporation sold 0.8 million and 2.2 million shares under its February 2015 equity distribution agreement for cash proceeds of $49 million and $123 million, respectively, net of commissions paid of $0.4 million and $1 million, respectively. As of June 30, 2016, the remaining gross sales available under this agreement were $301 million.

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 six months ended June 30, 2016, 4 million shares were issued for cash proceeds of $165 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 six months ended June 30, 2016, PG&E Corporation made equity contributions to the Utility of $280 million.

In March 2016, the Utility issued $600 million principal amount of 2.95% Senior Notes due March 1, 2026. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper. In addition, in March 2016, the Utility entered into a $250 million floating rate unsecured term loan that matures on February 2, 2017. 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

In June 2016, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2020 to April 27, 2021. At June 30, 2016, PG&E Corporation and the Utility had $300 million and $1.7 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.)

PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $1.75 billion, respectively. For the six months ended June 30, 2016, PG&E Corporation and the Utility had an average outstanding commercial paper balance of $53 million and $813 million, and a maximum outstanding balance of $176 million and $1.3 billion, respectively. At June 30, 2016, the Utility had an outstanding commercial paper balance of $1.3 billion and PG&E Corporation did not have any commercial paper outstanding.

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. At June 30, 2016, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 52% and 51%, respectively. 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, the revolving credit facilities include usual and customary provisions regarding events of default and covenants including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, and imposing conditions on the sale of all or substantially all of PG&E Corporation's and the Utility's assets and other fundamental changes. At June 30, 2016, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

The Board of Directors of PG&E Corporation and the Utility have each adopted a new target dividend payout ratio range of 55% to 65% of earnings, with a target to reach a payout ratio of approximately 60% by 2019. Each Board of Directors retains authority to change the respective common stock dividend policy and dividend payout ratio at any time, especially if unexpected events occur that would change its view as to the prudent level of cash conservation. No dividend is payable unless and until declared by the applicable Board of Directors.

In May 2016, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.49 per share, totaling $244 million, of which approximately $239 million was paid on July 15, 2016, to shareholders of record on June 30, 2016.

In May 2016, the Board of Directors of the Utility declared a common stock dividend of $244 million that was paid to PG&E Corporation on June 1, 2016.

In May 2016, the Board of Directors of the Utility declared dividends on its outstanding series of preferred stock, payable on August 15, 2016, to shareholders of record on July 29, 2016.

Utility Cash Flows

The Utility's cash flows were as follows:

	Six Months Ended June 30, 2016	
(in millions)	2016	2015
Net cash provided by operating activities	$1,769	$1,860
Net cash used in investing activities	(2,686)	(2,486)
Net cash provided by financing activities	978	719
Net change in cash and cash equivalents	$61	$93

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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 six months ended June 30, 2016, net cash provided by operating activities decreased by $91 million compared to the same period in 2015. This decrease was primarily due to the shareholder-funded bill credit of $400 million, as required by the Penalty Decision, which was refunded to natural gas customers in the second quarter of 2016. This decrease was partially offset by state income tax refunds received in 2016.

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

- the timing and amounts of fines or penalties that may be imposed in connection with the criminal prosecution of the Utility and the remaining investigations and other enforcement and litigation matters (see Note 9 of the Notes to the Condensed Consolidated Financial Statements);
- the timing and outcome of ratemaking proceedings, including of a final phase two decision in the 2015 GT&S rate case and of the 2017 GRC;
- 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 (including the bonus depreciation), 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 $200 million during the six months ended June 30, 2016 as compared to the same period in 2015. 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 $5.6 billion in capital expenditures in 2016 and between $5.4 billion and $6.4 billion in 2017.

Financing Activities

During the six months ended June 30, 2016, net cash provided by financing activities increased by $259 million compared to the same period in 2015. 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. In addition, PG&E Corporation and the Utility are involved in other enforcement and litigation matters described in the 2015 Form 10-K and Part II. Other Information, Item 1. Legal Proceedings. Significant regulatory developments that have occurred since the 2015 Form 10-K was filed with the SEC are discussed below.

Department of Interior Inquiry

In September 2015, the Utility was notified that the 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 federal criminal indictment discussed in Note 9 of the Notes to the Condensed Consolidated Financial Statements. The Utility filed 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. On April 8, 2016, the Utility received a series of follow-up questions from the DOI regarding the Utility's November 2015 submission. The Utility continues to fully cooperate with the DOI and expects to start providing responses to these follow-up questions beginning in August 2016. It is uncertain when or if further action will be taken by DOI following the Utility's response.

Litigation Related to the San Bruno Accident and Natural Gas Spending

As of June 30, 2016, there were seven 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 as the San Bruno Fire Derivative Cases and are pending in the Superior Court of California, County of San Mateo. The remaining three cases are Tellardin v. PG&E Corp. et al., Iron Workers Mid-South Pension Fund v. Johns, et al., and Bushkin v. Rambo et al.

On December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County, ordering the court to stay all proceedings in the four consolidated San Bruno Fire Derivative Cases pending conclusion of the federal criminal proceedings against the Utility.

Bushkin v. Rambo et al., pending in the United States District Court for the Northern District of California, has been designated by the plaintiff as related to the pending shareholder derivative suit Iron Workers Mid-South Pension Fund v. Johns, et al., discussed below. The plaintiff in the Bushkin lawsuit has agreed that this case should be stayed pending conclusion of the federal criminal proceedings against the Utility and, on May 3, 2016, the judge entered a stipulated order staying the case. The order also provides that the parties should meet and confer within 30 days after the criminal trial concludes and provide the court a status update. Despite the stay of his complaint, on June 20, 2016 the Bushkin plaintiff filed a petition in the Superior Court of California, San Francisco County, seeking to enforce the plaintiff's claimed right as a shareholder to inspect certain PG&E Corporation accounting books and records pursuant to section 1601 of the California Corporations Code. On July 25, 2016, PG&E Corporation filed a motion to stay plaintiff's petition until the appellate stay of the San Bruno Fire Derivative Cases has been lifted, or, in the alternative, a demurrer asking the Court to dismiss plaintiff's petition.

The Iron Workers action pending in the United States District Court for the Northern District of California has been stayed pending the resolution of the San Bruno Fire Derivative Cases. On May 5, 2016, the court ordered the parties to meet and confer within 30 days after the criminal trial concludes and provide the court a status update.

A case management conference in the action entitled Tellardin v. PG&E Corp. et al., also pending in the Superior Court of California, San Mateo County, is currently set for August 9, 2016.

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

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. Significant regulatory developments that have occurred since the 2015 Form 10-K was filed with the SECare discussed below.

2017 General Rate Case

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.)

The Utility’s supplemental testimony filed on February 22, 2016, reduced the Utility's previously requested 2017 revenue requirement increase of $457 million (as compared to the 2016 authorized amount of $7.9 billion) to $333 million. In its rebuttal testimony that the Utility submitted to the CPUC on May 27, 2016, the Utility further reduced its 2017 requested revenue requirement by $14 million, to $319 million, representing a $138 million reduction from the original request. The requested increase for 2018 was reduced from $489 million to $467 million, and the requested increase for 2019 was reduced from $390 million to $368 million. The Utility reduced its requested increase primarily to reflect the impact of the five-year extension of the federal tax code provisions regarding bonus depreciation, as well as the tax-deductibility of repair costs.

The table below summarizes the differences between the Utility’s revenue requirement increase proposal (as revised in the Utility’s May 27, 2016 rebuttal testimony), and ORA’s and TURN’s recommendations:

Year	Utility's Proposal (in millions)	ORA's Recommendation (in millions) Increase / (Decrease)	Difference (1) Increase / (Decrease)	TURN's Recommendation (in millions) Increase / (Decrease)	Difference (1) Increase/(Decrease)
2017	$319	$(85)	$(404)	$ N/A (2)	$N/A
2018	467	274	(193)	469	2
2019	368	283	(85)	250	(118)
2020	N/A	294 (3)	N/A	N/A	N/A

(1) Reflects the difference between the Utility’s proposal and the recommendation.

(2) TURN’s proposal does not include a revenue requirement recommendation for 2017.

(3) Reflects ORA’s recommendation to extend the GRC cycle another year.

The following table shows the difference between the Utility’s requested increases in 2017 revenue requirements (as revised in the Utility’s May 27, 2016 rebuttal testimony) and ORA’s recommended amounts by line of business (TURN did not present revenue requirement recommendations by line of business):

(in millions) Line of Business:	Utility's Proposal		ORA's Recommendation Increase / (Decrease)		Difference (1) Increase / (Decrease)
Electric distribution	$67	1.6 %	$(145)	(3.5) %	$(212)
Gas distribution	59	3.4	(59)	(3.4)	(118)
Electric generation	193	9.8	119	6.1	(74)
Total revenue requirement increases	$319	4.0 %	$(85)	(1.1) %	$(404)

(1) Reflects the difference between the Utility’s proposal and ORA’s recommendation.

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The following tables show the Utility's currently requested amounts compared to 2016 authorized amounts:

(in millions) Line of Business:	Amounts Requested	Amounts Currently Authorized For 2016	Increase Compared to Currently Authorized Amounts
Electric distribution	$4,279	$4,212	$67
Gas distribution	1,801	1,742	59
Electric generation	2,155	1,962	193
Total revenue requirements	$8,235	$7,916	$319
Cost Category: (in millions)			
Operations and maintenance	$1,825	$1,664	$161
Customer services	361	319	42
Administrative and general	975	1,011	(36)
Less: Revenue credits	(140)	(131)	(9)
Franchise fees, taxes other than income, and other adjustments	184	37	147
Depreciation (including costs of asset removal), return, and income taxes	5,030	5,016	14
Total revenue requirements	$8,235	$7,916	$319

In order to allow settlement discussions to proceed, on June 23, 2016, the CPUC revised the procedural schedule for the 2017 GRC. Under the current schedule, evidentiary hearings will be held in August and September 2016, followed by a proposed decision to be released in January 2017 and a final CPUC decision to be issued in February 2017. On March 17, 2016, the CPUC issued a decision to allow the authorized revenue requirement changes to become effective on January 1, 2017, even if the final decision is issued after that date.

On July 21, 2016, the Utility, together with ORA, TURN, and nearly all other parties active in the proceeding, filed a notice to all parties that a settlement conference in the Utility's 2017 GRC will be held on August 3, 2016. Such notice is required by the CPUC rules. The settlement conference will be open to all parties in the proceeding and is intended to consider the execution of a settlement agreement.

If the parties are able to reach settlement, the parties would file a motion before the CPUC for approval of a settlement agreement. A settlement agreement would be subject to comments by parties, workshops or hearings, and the CPUC approval. The schedule for such activities would be determined by the CPUC.

PG&E Corporation and the Utility are unable to predict whether the parties will be able to reach a settlement agreement and whether the CPUC will approve such settlement agreement.

For more information, see Item 4 of the 2015 Form 10-K and Item 2 of the 2016 Q1 Form 10-Q.

2015 Gas Transmission and Storage Rate Case

On June 23, 2016, the CPUC approved a final decision in phase one of the Utility's 2015 GT&S rate case. The decision adopts the revenue requirements that the Utility will be authorized to collect through rates beginning August 1, 2016, to recover its costs of gas transmission and storage services for the 2015 GT&S rate case period. In this decision, the CPUC determined it will issue a phase two decision to reduce the authorized revenue requirements after considering comments from parties on the allocation of the $850 million of shareholder funded safety work related to the Penalty Decision, including (1) which programs and projects should be considered safety-related, and (2) whether the percentage of the disallowance that should be applied to capital expenditures as opposed to expense should be changed. (As previously disclosed, the Penalty Decision disallows the Utility from recovering $850 million of costs associated with future pipeline safety-related projects and programs to be designated by the CPUC, with a minimum of $689 million of the costs to be capital related.)

The following table shows the revenue requirement amounts requested by the Utility in the 2015 GT&S rate case and the revenue requirement amounts adopted in the CPUC decision, subject to future adjustments for the $850 million San Bruno penalty:

(in millions)	2015	2016	2017	2018 (2)
Utility Requested Revenue Requirement	$1,263	$ 1,346	$ 1,488	$ N/A
"Interim" Revenue Requirement	1,046	1,110	1,220	1,324
"Placeholder" Ex Parte Penalty (1)	(138)			
Revenue Requirement Before Penalty Decision Disallowance	908	1,110	1,220	1,324

(1) The revenue requirement is reduced by $138 million in 2015 for the disallowance associated with the 5-month delay caused by the Utility's violation of the CPUC ex parte communication rules in this proceeding, subject to modification after the revenue requirement is adjusted for the $850 million San Bruno penalty.

(2) Due to the delay in issuing this Decision, the CPUC adopted a third year of attrition revenues for 2018.

In 2015, the Utility's GT&S revenues were approximately $550 million. The decision authorizes the Utility to collect, over a 36-month period, the difference between adopted revenue requirements and amounts previously collected in rates, retroactive to January 1, 2015. Due to the uncertainty regarding the revenue requirement the CPUC will ultimately adopt in its phase two decision, after allocation of the $850 million Penalty Decision disallowance (and the resulting adjustment of the ex parte disallowance), the Utility will not be able to record the revenue requirement increase since January 1, 2015 until after the phase two decision is issued. In addition, accounting rules allow the Utility to recognize revenues in a given year only if they will be collected from customers within 24 months of the end of that year. As a result, the Utility will not be able to complete recording the full retroactive revenue requirement increase until 2017.

The decision adopts capital expenditures of roughly $700 million to $800 million per year through 2018 and authorizes weighted average rate base of $2.9 billion in 2015, $3.3 billion in 2016, $3.6 billion in 2017, and $4.2 billion in 2018. The authorized weighted average rate base excludes $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallows $120 million of that amount and orders that the remaining $576 million be subject to a third party audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The decision also establishes various cost caps that will increase the risk of overspend over the current rate case cycle including new one-way capital balancing accounts. As a result, during the three and six months ended June 30, 2016 the Utility incurred charges of $190 million for capital expenditures that the Utility believes are probable of disallowance based on the decision. This includes $134 million to the net plant balance for 2011 through 2014 capital expenditures in excess of adopted amounts and $56 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the third party audit of 2011through 2014 capital spending.

The decision denies the Utility's request for full balancing account treatment for recovery of authorized transportation and storage revenue requirements, and instead continues the revenue sharing mechanism authorized in the 2011 GT&S rate case that subjects a portion of the Utility's transportation and storage revenue requirement to market risk.

The decision also authorizes the Utility's request for cost recovery of up to $157 million for the construction of Line 407, a 25.5 mile, 30-inch pipeline in the Sacramento Valley expected to be built during this rate case period. The authorized revenue requirements will begin when Line 407 becomes operational, subject to refund upon a reasonableness review in the Utility's next GT&S rate case. The decision authorizes the Utility to track costs exceeding $157 million and seek recovery in the next GT&S rate case, subject to a reasonableness review.

With the addition of a third attrition year, the Utility's next GT&S cycle will begin in 2019. The decision requires the Utility to file its next GT&S application in 2017.

On July 6, 2016, Indicated Shippers filed a motion to compel with the CPUC, requesting that the Utility submits information regarding rate impacts of various scenarios of the penalty implementation. In addition, on July 7, 2016, several parties filed opening briefs on the allocation of the $850 million Penalty Decision disallowance. In their briefs, some parties recommended that the $850 million be allocated to 100 percent expense to mitigate rate impacts. On July 8, 2016, the ALJ issued a ruling granting in part the motion to compel filed by the Indicated Shippers and, as a result, modified the briefing schedule. Supplemental opening briefs were submitted on July 26 and reply briefs are due on August 2, 2016. The Utility expects that the CPUC will issue a phase two decision within 90 days of the reply briefs.

For more information, see Item 4 of the 2015 Form 10-K and Item 2 of the 2016 Q1 Form 10-Q.

FERC Transmission Owner Rate Cases

On July 29, 2015, the Utility requested 2016 retail electric transmission revenue requirement of $1.515 billion, a $314 million increase over the currently authorized revenue requirement of $1.201 billion. The Utility's proposed rates went into effect on March 1, 2016, subject to refund, and pending a final decision by the FERC. The parties to this proceeding are in settlement discussions. If a settlement is reached by the parties, it will be subject to the FERC's approval. If settlement is not reached, the proceeding will be set for hearing and depending on the timing of such a hearing, the Utility expects that the FERC will issue a decision in mid to late 2017.

The Utility expects to file a rate case at FERC to request a 2017 retail electric transmission revenue requirement on July 29, 2016. The Utility expects to indicate that it will make investments of $1.296 billion in 2017 in various capital projects. The Utility also expects to indicate that its forecasted rate base for 2017 is $6.713 billion, compared to forecasted rate base of $5.85 billion in 2016. A FERC order accepting the Utility's filing, setting an effective date for rates, subject to hearing and refund, is expected by September 30, 2016. While the Utility will request that the new rates be effective on October 1, 2016, subject to refund, pending a final decision by the FERC, the Utility anticipates that the rates will be suspended for five months and made effective on March 1, 2017, subject to refund.

CPUC Cost of Capital Decision

On February 25, 2016, the CPUC issued a decision granting a petition for modification filed by the Utility and the other two California investor-owned electric utilities to clarify that the CPUC's previously adopted cost of capital adjustment mechanism would not be triggered before their 2018 cost of capital applications are due on April 20, 2017. As a result, the Utility's currently authorized return on equity of 10.40% and capital structure, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock, will remain the same for 2017.

Diablo Canyon Nuclear Power Plant

Joint Proposal for Plant Retirement

On June 20, 2016, the Utility entered into a joint proposal with Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and Alliance for Nuclear Responsibility to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a GHG-free portfolio of energy efficiency, renewables, and energy storage.

The joint proposal also includes a voluntary increase in the Utility's target for RPS-eligible resources to 55 percent, effective in 2031 through 2045, as compared to the state's goal of 50 percent renewables. The parties to the joint agreement proposed that the Utility be authorized to procure GHG-free replacement resources in three competitive procurement tranches: in Tranche 1, the Utility would be authorized to obtain 2,000 gross GWH of energy efficiency savings to be implemented over the 2018 to 2024 time period; in Tranche 2, the Utility would be authorized to procure 2,000 GWH of GHG-free energy resources through an all-source solicitation that will commence energy deliveries or add energy efficiency programs or projects to the system in the 2025 to 2030 time period, and; in Tranche 3, the Utility commits to a voluntary 55 percent RPS, and will maintain this voluntary commitment through 2045 or until superseded by action of the state legislature or the CPUC. The three tranches of resource procurement proposed in the joint proposal are not intended to specify all energy resources that will be needed to ensure the orderly replacement of Diablo Canyon. Instead, the Utility expects that the full solution will emerge over the 2024-2045 period.

Costs associated with energy efficiency programs in Tranche 1 and Tranche 2 would be recovered through the Utility's electric public purpose program rates as non-bypassable charges, consistent with the existing recovery mechanisms for energy efficiency program costs. GHG-free energy resources costs from Tranche 2 would be subject to a non-bypassable cost allocation mechanism called the Clean California Charge that (1) equitably allocates costs and benefits, such as RPS or Resource Adequacy credits, associated with the procurement among responsible load-serving entities, and (2) determines the net capacity costs of such procurement consistent with the methodology for the allocation of net capacity costs laid out by the CPUC. Costs associated with procurement for Tranche 3 would be recovered through a separate renewable non-bypassable charge.

The joint proposal seeks confirmation from the CPUC that the Utility's full investment in Diablo Canyon and authorized rate of return will be recovered in rates by the time the facility ceases operations. Additionally, the Utility requests that the CPUC pre-approve the recovery of certain costs related to the closure of the Diablo Canyon. These include the non-bypassable cost allocation mechanism for procurement of GHG-free energy and the recovery of $1.3 billion for administration and acquisition of the new Tranche 1 energy efficiency procurement as authorized energy efficiency funding, subject to return of all unspent funds; the recovery of employee retention and retraining and development programs to continue safe and efficient operation of Diablo Canyon through the end of its license periods, estimated at approximately $350 million; and a community mitigation program to compensate San Luis Obispo County for the decline in local economic stimulus provided by Diablo Canyon through a transition period ending in 2025, estimated at approximately $50 million. The Utility also seeks cost recovery of approximately $50 million in costs related to the federal and state Diablo Canyon license renewal process.

The Utility expects to submit its application to the CPUC to approve the joint proposal and cost recovery requests included therein, as well as the resulting revenue requirements in August 2016. Upon CPUC approval of the application, the Utility will withdraw its license renewal application currently pending before the NRC when such approval has become final and non-appealable. PG&E Corporation and the Utility are unable to predict whether the CPUC will approve the joint proposal application.

California State Lands Commission Lands Lease

On June 28, 2016, California State Lands Commission approved a new lands lease for the intake and discharge structures at Diablo Canyon to run concurrently with Diablo Canyon's current operating licenses, until Diablo Canyon Unit 2 ceases operations in August 2025. The Utility believes that the approval of the New Lease will ensure sufficient time for the Utility to identify and bring online a portfolio of GHG-free replacement resources. The Utility will submit a future lease extension request to address the period of time required for plant decommissioning, which under NRC regulations can take as long as 20 years.

Asset Retirement Obligations

The Utility expects that the decommissioning of Diablo Canyon will take many years after the expiration of its current operating licenses. Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. Actual decommissioning costs may vary from these estimates as a result of changes in assumptions such as decommissioning dates; regulatory requirements; technology; and costs of labor, materials, and equipment. The Utility recovers its revenue requirements for decommissioning costs from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

On March 1, 2016, the Utility submitted its updated decommissioning cost estimate with the CPUC. The estimated undiscounted cost to decommission the Utility's nuclear power plants increased by approximately $1.4 billion, for a total estimated cost of $4.8 billion, due to increased estimated costs related to spent fuel storage, staffing, and out-of-state waste disposal. The Utility requested that the CPUC authorize the collection of increased annual revenue requirements beginning on January 1, 2017 based on these updated cost estimates. Additionally, as a result of the joint proposal discussed above, an increase of $115 million to the ARO was recognized on the Condensed Consolidated Balance Sheets at June 30, 2016.

While the NDCTP forecast includes employee severance program estimates, it does not include estimated costs related to the joint proposal's employee retention and retraining and development programs, and the San Luis Obispo County community mitigation program described above. The Utility intends to conduct a site-specific decommissioning study to update the 2015 NDCTP forecast and to submit the study to the CPUC by mid-2019.

On July 15, 2016, the assigned CPUC Commissioner and ALJ issued a scoping memo for the Utility's 2015 NDCTP and excluded from the scope of the proceeding the issue on whether the Utility should be required to present additional analysis for a license extension scenario for Diablo Canyon, as a result of the Utility's announcement of its plan to not seek relicensing of Diablo Canyon beyond its current operating authority. The scoping memo also adopts within the scope of the proceeding a reasonableness review of the Utility's estimated updated cost to decommission the Utility's nuclear power plants and of the forecasts of certain expenses and the decommissioning trust funds' rates of return. According to the scoping memo, intervenor testimony is due in August 2016, rebuttal testimony and evidentiary hearings will take place in September 2016, and opening and reply briefs will be submitted in October 2016.

The estimated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Condensed Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued in accordance with GAAP was $3.4 billion at June 30, 2016, which includes an $818 million adjustment to reflect the increased cost estimates and the $115 million increase resulting from the joint proposal described above, and $2.5 billion at December 31, 2015. These estimates are based on decommissioning cost studies, prepared in accordance with the CPUC requirements. Changes in these estimates could materially affect the amount of the recorded ARO for these assets.

As of June 30, 2016, the nuclear decommissioning trust accounts' total fair value was $2.9 billion. Changes in the estimated costs, the timing of decommissioning or the assumptions underlying these estimates could cause material revisions to the estimated total cost to decommission.

For additional information, see the 2015 Form 10-K and the 2016 Q1 Form 10-Q.

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 consultant's work began in the second quarter of 2016.

The CPUC stated that the initial phase of the proceeding was categorized as rate setting 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.

Rehearing of CPUC Decisions Approving 2006 – 2008 Energy Efficiency Incentive Awards

On September 17, 2015, the CPUC granted TURN's and ORA's long-standing applications for rehearing of the CPUC decisions that awarded energy efficiency incentive payments to the California IOUs for the 2006-2008 energy efficiency program cycle. Under the incentive ratemaking mechanism applicable to the 2006-2008 program cycle, the Utility could have earned incentive revenues up to a maximum of $180 million, depending on the extent to which the Utility achieved the energy savings targets. Conversely, to the extent the Utility failed to achieve the targets, the Utility could have been required to offset future incentive earnings claims by amounts previously awarded, and, in addition, could have incurred penalties of up to $180 million. The Utility was awarded a total of $104 million for the 2006-2008 program cycle.

On June 24, 2016, the Utility, ORA, and TURN jointly filed a motion with the CPUC seeking approval of a settlement agreement to resolve all issues related to the 2006-2008 customer energy efficiency shareholder incentives. The settlement agreement requires the Utility to reduce certain future energy efficiency shareholder incentives by $29.1 million. The reduction of the shareholder incentive award will be applied in installments of $5.8 million per year for five years, provided that the Utility has sufficient energy efficiency incentive awards to offset that amount. If shareholder incentives are insufficient to offset this amount, the offset in the following year will be increased by the shortfall. At its discretion, the Utility may increase the amount of the offset to reduce the $29.1 million more quickly. If the amount has not been fully offset at the end of five years, the balance will be credited towards electric and gas rates. The first offset will be requested by the Utility in the September 1, 2016 shareholder incentive advice letter. The requested offset will be conditioned on final CPUC approval of the settlement agreement without modifications. It is uncertain whether the CPUC will approve the settlement agreement and when the CPUC will issue a decision.

Residential Rate Reform Rate Change

On February 17, 2016, the Utility filed a proposed rate change for rates to be billed to customers effective March 1, 2016. On February 29, 2016, the CPUC rejected the Utility's proposed rate change, stating that the rate design failed to comply with the requirements adopted in the Decision on Residential Rate Reform issued on July 3, 2015, that set a specific rate change "glidepath" for the Utility. The Utility began billing customers based on its proposed rates on March 1, 2016. On March 9, 2016, the assigned ALJ issued a ruling directing the Utility to show cause why the CPUC should not order sanctions and other remedies in response to the alleged non-compliance. On March 11, 2016, the Utility submitted its response in which it stated that its rates were in compliance with the CPUC's July 2015 decision and addressed the circumstances that make it impossible for the Utility to follow the "glidepath." On March 24, 2016, the Utility filed an additional advice letter proposing a new, three-tiered rate structure. On May 26, 2016, the CPUC approved the Utility's three-tiered rate structure and advice letter. The CPUC's approval recognized that the Utility's rates fulfill the requirements of the July 2015 decision as applied to the Utility's particular circumstances. As of the date of this report, the CPUC has not directly terminated its ruling to show cause or ordered sanctions or other remedies. The Utility is uncertain if the CPUC will impose any sanctions or other remedies, and if it does so, their amounts. The CPUC is not required to take any further action on its ruling to show cause.

For more information, see Item 2 of the 2016 Q1 Form 10-Q.

Utility-Owned PV Generation Cost Savings Incentive Award

In April 2010, the CPUC authorized the Utility to develop, own, and operate PV facilities and established a cost savings incentive mechanism which states that shareholders are eligible to retain ten percent of the difference between the actual average cost per unit and the threshold set by the CPUC. From 2011 – 2013, the Utility constructed nine PV projects with a total capacity of 150 MW and the weighted average unit capital cost came in below the CPUC specified threshold. In July 2016, the CPUC approved the recovery of $16 million in shareholder incentives related to these projects under the PV capital cost savings incentive mechanism.

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, promote customer energy efficiency and demand response programs, and implement new state law requirements applicable to natural gas storage facilities. 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. Significant developments that have occurred since the 2015 Form 10-K was filed with the SEC 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.

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.

Integrated Distributed Energy Resources – Regulatory Incentives Pilot Program

On April 4, 2016, the assigned CPUC Commissioner and ALJ issued a ruling proposing to establish, on a pilot basis, an interim program offering regulatory incentives to the Utility and the other two large California IOUs for the deployment of cost-effective DERs. The ruling assumes that the incentive would take the form of an additional payment to the utility of 3.5% (grossed up for taxes) of the payments made to the DER provider(s). The exact figure would be determined later if the proposal or a similar alternative is adopted by the CPUC. The ruling also states that it does not intend for this phase to adopt a new regulatory framework or business model for the California electric utilities.

On May 9 and May 23, 2016, the Utility, two other California utilities (the "Joint Utilities") and other parties filed their comments. The Joint Utilities indicate that providing a regulatory incentive to utilities to deploy DERs in place of distribution investment is premature until the operating and performance characteristics of DERs are better understood and evaluated as part of pilot projects. The Joint Utilities instead propose initiating DER pilots that would advance understanding of distribution deferral and DER procurement processes.

On June 17, 2016, the Utility filed revised proposals to conduct demonstration projects under its Distribution Resources Plan to test and demonstrate the operating and performance characteristics of DERs that could defer utility distribution capacity investments. The timing and schedule for CPUC review and approval of the demonstration projects and any regulatory incentive proposal is uncertain.

Electric Rate Reform and Net Energy Metering

On July 3, 2015, the CPUC approved a final decision to authorize the California IOUs to gradually flatten their tiered residential electric rate structures from four tiers to two tiers by January 1, 2019. The decision approved higher minimum bill charges for residential customers and 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 electric customers based on time-of-use rates (known as "default time-of-use rates") unless customers elect otherwise. The Utility also may propose to impose a fixed charge on residential electric 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 in electric rates.

In January 2016, the CPUC adopted new NEM rules and rates. The new rules and rates are expected to become effective for new NEM customers later in 2016, when the Utility is expected to reach its current NEM cap. The CPUC indicated that it will revisit the NEM successor tariff in 2019. New NEM customers will be required to pay an interconnection fee, will be charged on time-of-use rates, and will be required to pay non-bypassable charges to help fund some of the costs of low-income, energy efficiency, and other programs that other customers pay. On March 7, 2016, the Utility and certain other parties, including TURN and CUE, filed applications for rehearing. The Utility requested that the CPUC vacate its January 2016 decision that the Utility asserts contains legal and factual errors. Many parties argued that the CPUC failed to complete its duties under AB 327, which required the CPUC to evaluate the costs and benefits of NEM. On July 14, 2016, the CPUC held a closed session discussion on the parties' applications for rehearing (previously filed on March 7, 2016). The Utility is uncertain when the CPUC will issue a decision.

Electric Vehicle (EV) Infrastructure Development

In December 2014, the CPUC issued a decision adopting a policy to expand the California utilities' role in developing 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.

On March 21, 2016, the Utility filed with the CPUC a settlement agreement that it entered into with certain parties, including environmental advocates, automakers, electric vehicle drivers, labor, and environmental justice advocates, that makes adjustments to the Utility's second proposal, including a reduction to requested capital expenditures to approximately $132 million. (TURN, ORA, and certain equipment suppliers are not parties to the agreementand filed responses on April 12, 2016, generally opposing the settlement.) The settlement agreement is subject to approval by the CPUC. Hearings were held in April 2016 and a proposed decision for the first phase of the proceeding is expected to be issued in the third quarter of 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 13 in the 2015 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 2015 Form 10-K.

Off-Balance Sheet Arrangements

PG&E Corporation and the Utility do not have anyoff-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 13 of the Notes to the Consolidated Financial Statements in the 2015 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 physical 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. The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, and other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. These activities arediscussed in detail in the 2015 Form 10-K. There were no significant developments to the Utility and PG&E Corporation's risk management activities during the six months ended June 30, 2016.

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 2015Form 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.

FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. These forward-looking statements relate to, among other matters, estimated losses, including penalties and fines, associated with various investigations and proceedings; forecasts of pipeline-related expenses that the Utility will not recover through rates; forecasts of capital expenditures; estimates and assumptions used in critical accounting policies, including those relating to regulatory assets and liabilities, environmental remediation, litigation, third-party claims, and other liabilities; and the level of future equity or debt issuances. These statements are also identified by words such as "assume," "expect," "intend," "forecast," "plan," "project," "believe," "estimate," "predict," "antic "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results. Some of the factors that could cause future results to differ materially from those expressed or implied by the forward-looking statements, or from historical results, include, but are not limited to:

- the timing and outcomes of the final phase two CPUC decision in the 2015 GT&S rate case, the 2017 GRC, the TO rate cases, and other ratemaking and regulatory proceedings;
- the timing and outcomes of the federal criminal prosecution of the Utility, the CPUC decision in the Utility's natural gas distribution record-keeping practices investigation, the SED's unresolved enforcement matters relating to the Utility's compliance with natural gas-related laws and regulations, 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 ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;
- the timing and outcomes of the CPUC's investigation of 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 of the U.S. Attorney's Office in San Francisco and the California Attorney General's office investigations in connection with communications between the Utility's personnel and CPUC officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and the extent to which such matters negatively affect the final decisions to be issued in the Utility's ratemaking proceedings;
- the outcome of the Butte fire litigation, and whether the Utility's insurance is sufficient to cover the Utility's liability resulting therefrom or if insurance is otherwise available; and whether additional investigations and proceedings will be opened;
- 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, matters relating to the indicted case, improper communications between the CPUC and the Utility; and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;
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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, including the dilutive impact of common stock issuances to fund PG&E Corporation's equity contributions to the Utility as the Utility incurs charges and costs, including fines, that it cannot recover through rates;
- the outcome of the CPUC's investigation into the Utility's safety culture, and future legislative or regulatory actions that may be taken to require the Utility to separate its electric and natural gas businesses, restructure into separate entities, undertake some other corporate restructuring, or implement corporate governance changes;
- 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;

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- the impact of environmental remediation laws, regulations, and orders; the ultimate amount of costs incurred to discharge the Utility's known and unknown remediation obligations; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;
- the ultimate amount of unrecoverable environmental costs the Utility incurs 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; the impact of actions taken by state agencies, that may affect the Utility's ability to continue operating Diablo Canyon; whether the CPUC approves the joint proposal that will phase out the Utility's Diablo Canyon nuclear units at the expiration of their licenses in 2024 and 2025; whether the Utility obtains the approvals required to withdraw its NRC application to renew the two Diablo Canyon operating licenses; and whether the Utility will be able to successfully implement its retention and retraining and development programs for Diablo Canyon employees, and whether these programs will be recovered in rates;
- whether the Utility's information technology, operating systems and networks, including the advanced metering system infrastructure, customer billing, financial, records management, and other systems, can continue to function accurately while meeting regulatory requirements; whether the Utility and its third party vendors and contractors (who host, maintain, modify and update some of the Utility's systems) are able to protect the Utility's 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, including confidential proprietary information and the personal information of customers; and whether the Utility can continue to rely on third-party vendors and contractors that maintain and support some of the Utility's information technology and operating systems;
- the impact of droughts or other weather-related conditions or events, wildfires (such as the Butte fire), 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; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; and whether the Utility is subject to civil, criminal, or regulatory penalties in connection with such events; and whether the Utility's insurance coverage is available for these types of claims and whether the amount of insurance is sufficient to cover the Utility's liability;
- how the CPUC and the CARB implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, distributed energy resources, electric vehicles, and similar matters, including 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 is able to timely recover its associated investment costs;
- whether the Utility's climate change adaptation strategies are successful;
- 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 is successful in addressing the impact of growing distributed and renewable generation resources and changing customer demand for natural gas and electric services;

- 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, including its renewable energy procurement costs;

- 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;

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- changes in credit ratings which could result in increased borrowing costs especially if PG&E Corporation or the Utility were to lose its investment grade credit ratings;
- the impact of federal or state laws or regulations, or their interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility’s holding company, and whether the ultimate outcomes of the 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; 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 2015 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 June 30, 2016, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective to ensure that information required to be disclosed by PG&E Corporation and the Utility in reports that the companies file or submit under the Securities Exchange Act of 1934 is recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms. In addition, PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers have concluded that such controls and procedures were effective in ensuring that information required to be disclosed by PG&E Corporation and the Utility in the reports that PG&E Corporation and the Utility file or submit under the Securities Exchange Act of 1934 is accumulated and communicated to PG&E Corporation's and the Utility's management, including PG&E Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

There were no changes in internal control over financial reporting that occurred during the quarter ended June 30, 2016, 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 Statement and Part I, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations, "Enforcement and Litigation Matters."

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

For a description of this matter, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K, the discussion of the Penalty Decision in Note 13 of the Notes to the Consolidated Financial Statements inthe 2015 Form 10-K, and the discussion included in Note 9 of the Notes to the Condensed Consolidated Financial Statements.

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 superseded 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. On December 23, 2015, the court presiding over the federal criminal proceeding dismissed 15 of the Pipeline Safety Act counts, leaving 13 remaining counts. The trial began on June 14, 2016. On July 26, 2016, the court granted the government's motion to dismiss Count 13 alleging that the Utility knowingly and willfully failed to retain strength pressure test record with respect to a distribution feeder main (DFM1816-01). Therefore, the number of counts has been reduced from 13 to 12. On July 27, 2016, the parties completed delivering their closing arguments and the case was submitted to the jury. The Utility is unable to predict when and if the jury will return its verdict.

The maximum statutory fine for each felony count is $500,000, for total potential fines of $6 million. The government is also seeking fines under the Alternative Fines Act. The Alternative Fines Act 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.” On December 8, 2015, the court issued an order granting, in part, the Utility’s request to dismiss the government’s allegations seeking an alternative fine under the Alternative Fines Act. The court dismissed the government’s allegations regarding the amount of losses, but concluded that it required additional information about how the government would prove its allegations about the amount of gross gains prior to deciding whether to dismiss those allegations. Based on the superseding indictment’s allegation that the Utility derived gross gains of approximately $281 million, the potential maximum alternative fine would be approximately $562 million. On February 2, 2016, the court issued an order holding that if the government’s allegations about the Utility’s gross gains are considered, they would be considered in a second trial phase that would take place after the trial on the criminal charges.

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. PG&E Corporation and the Utility have not accrued any charges for criminal fines in their Condensed Consolidated Financial Statements as such amounts were not considered to be probable.

For description of this matter, see “Part I, Item 3. Legal Proceedings” in the 2015 Form 10-K, the section entitled “Enforcement and Litigation Matters” in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 in the 2015 Form 10-K, and the section 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 June 30, 2016, there were seven 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 as the San Bruno Fire Derivative Cases and are pending in the Superior Court of California, County of San Mateo. The remaining three cases are Tellardin v. PG&E Corp. et al.,Iron Workers Mid-South Pension Fund v. Johns, et al., and Bushkin v. Rambo et al.

On December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County, ordering the court to stay all proceedings in the four consolidated San Bruno Fire Derivative Cases pending conclusion of the federal criminal proceedings against the Utility.

Bushkin v. Rambo et al., pending in the United States District Court for the Northern District of California, has been designated by the plaintiff as related to the pending shareholder derivative suit Iron Workers Mid-South Pension Fund v. Johns, et al., discussed below. The plaintiff in the Bushkin lawsuit has agreed that this case should be stayed pending conclusion of the federal criminal proceedings against the Utility and, on May 3, 2016, the judge entered a stipulated order staying the case. The order also provides that the parties should meet and confer within 30 days after the criminal trial concludes and provide the court a status update. Despite the stay of his complaint, on June 20, 2016 the Bushkin plaintiff filed a petition in the Superior Court of California, San Francisco County, seeking to enforce the plaintiff's claimed right as a shareholder to inspect certain PG&E Corporation accounting books and records pursuant to section 1601 of the California Corporations Code. On July 25, 2016, PG&E Corporation filed a motion to stay plaintiff's petition until the appellate stay of the San Bruno Fire Derivative Cases has been lifted, or, in the alternative, a demurrer asking the Court to dismiss plaintiff's petition.

The Iron Workers action pending in the United States District Court for the Northern District of California has been stayed pending the resolution of the San Bruno Fire Derivative Cases. On May 5, 2016, the court ordered the parties to meet and confer within 30 days after the criminal trial concludes and provide the court a status update.

A case management conference in the action entitled Tellardin v. PG&E Corp. et al., also pending in the Superior Court of California, San Mateo County, is currently set for August 9, 2016.

PG&E Corporation and the Utility are uncertain when and how the above lawsuits 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 2015 Form 10-K.

Butte Fire Litigation

On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the “Butte fire,” the wildfire that ignited and spread in Amador and Calaveras Counties in Northern California in September 2015. Cal Fire’s report concluded that the wildfire was caused when a Gray Pine tree contacted the Utility’s electric line which ignited portions of the tree, and determined that the failure by the Utility and its vegetation management contractors to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its vegetation management contractors in the Superior Court of California for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. Approximately 44 complaints have been filed to date against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving approximately 1,550 individual plaintiffs and their insurance companies. These complaints are now part of the master complaints. The number of individual complaints and plaintiffs may increase in the future.

Plaintiffs have begun to present to the Utility claims seeking early resolution of preference cases (individuals who due to their age and/or physical condition are not likely to meaningfully participate in a trial under normal scheduling). The Utility has begun mediating and settling these preference cases. A case management conference was held on July 14, 2016 and the next case management conference is scheduled for September 1, 2016.

In connection with this matter, the Utility may be liable for property damages without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire.

As a result of the Cal Fire report, additional investigations and proceedings may be opened, the outcome of which PG&E Corporation and the Utility are unable to predict.

For additional information see Note 9 of the Notes to the Condensed Consolidated Financial Statements and Item 1A. Risk Factors.

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 I, 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 2015 Form 10-K.

Diablo Canyon Nuclear Power Plant

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with GHG-free portfolio of energy efficiency, renewables and energy storage. The Utility expects that its decision to retire Diablo Canyon will affect the terms of the final settlement agreementbetween the Utility, the Central Coast Water Board and the California Attorney General's Office. Also, as required under the California State Water Resources Control Board's Once-Through Cooling Water Policy, beginning in 2016, the Utility will pay an annual interim mitigation fee until operations cease at the end of the current licenses.

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

For more information regarding the 2003 settlement agreement between the Central Coast Water Board, the Utility, and the California Attorney General's Office, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

Venting Incidents in San Benito County

As part of its regular maintenance and inspection practices for its natural gas transmission system, the Utility performs in-line inspections of pipelines using devices called "pigs" that travel through the pipeline to inspect and clean the walls of the pipe. When in-line inspections are performed, natural gas in the pipeline must be released or vented at the pipeline station where the device is removed. In February 2014, the Utility conducted an in-line inspection of a natural gas transmission pipeline that traverses San Benito County and vented the natural gas at the Utility's transmission station located in Hollister, which is next to an elementary school. The Utility vented the natural gas during school hours on three occasions that month. After being informed of the venting by the local air district, the San Benito County District Attorney notified the Utility in December 2014 that it was contemplating bringing a civil legal action against the Utility for violation of Health and Safety Code section 41700, which prohibits discharges of air contaminants that cause a public nuisance. On October 28, 2015, the district attorney informed the Utility that it would seek civil penalties in excess of $100,000 but is willing to continue to explore settlement options with the Utility. The Utility remains in settlement discussions with the district attorney's office.

For more information, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

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Transformer Oil Release in Sonoma County

During a rain storm in February 2015, transformer oil was released into an underground vault in the City of Santa Rosa, in Sonoma County, while a Utility crew was replacing a broken transformer. Following further rains, the oil released from the vault and reached a nearby creek. The event was investigated by Santa Rosa Fire Department, the local environmental enforcement authority, and later referred to the Sonoma County District Attorney's Office. In May 2016, the District Attorney informed the Utility that it would seek penalties and costs in excess of $100,000 for alleged violations of several sections of the California Health and Safety and California Government codes which prohibit unauthorized spills or releases of oil into waters of the state and require that releases be reported to the Office of Emergency Services. The Utility is in the process of settlement negotiations with the Sonoma County District Attorney's Office.

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 2015 Form 10-K entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Forward-Looking Statements."

PG&E Corporation and the Utility may incur material liability in connection with the Butte fire.

On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the "Butte fire," the wildfire that ignited and spread in Amador and Calaveras Counties in Northern California in September 2015. Cal Fire's report concluded that the wildfire was caused when a Gray Pine tree contacted an electric line of the Utility, which ignited portions of the tree, and determined that the failure by the Utility and its vegetation management contractors to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree. In a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

Approximately 44 individual complaints have been filed to date against the Utility and its vegetation management contractors in the Superior Court of California in both the County of Calaveras and the County of San Francisco, involving approximately 1,550 individual plaintiffs and their insurance companies. These complaints are now pending in a coordinated proceeding in the Superior Court of California for the County of Sacramento and part of two master complaints. The number of individual complaints and plaintiffs may increase in the future.

PG&E Corporation's and the Utility's financial statements for the period ended June 30, 2016 reflect a provision of $350 million for property damages in connection with this matter, which corresponds to the lower end of the range of its reasonably estimable losses. This amount is based on estimates about the number, size, and type of structures damaged or destroyed, and assumptions about the contents of such structures and other property damage. The Utility currently is unable to reasonably estimate the upper end of the range because it is at an early stage of the evaluation of claims and the mediation and settlement process. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations during the period in which such change occurred. The Utility also could incur material charges related to fire suppression, personal injury damages and other damages.

The Utility has insurance coverage for third party claims. At June 30, 2016, the Utility recorded $260 million for probable insurance recoveries in connection with recovery of losses related to the Butte fire. The Utility plans to seek full recovery of all insured losses and while the Utility believes that a significant portion of costs incurred for third-party claims (and associated legal expenses) relating to Butte fire will ultimately be recovered through its insurance, it is unable to predict the amount and timing of such insurance recoveries. If the amount of insurance is insufficient to cover such losses, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows 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.

The Utility's operational and information technology systems could fail to function properly or be improperly accessed or damaged by third parties (including cyberand physical attacks) or damaged by severe weather, natural disasters, or other events. Any of these events could disrupt the Utility's operations and cause the Utility to incur unanticipated losses and expense or liability.

The operation of the Utility's extensive electricity and natural gas systems relies on evolving and increasingly complex operational and information technology systems and network infrastructures that are interconnected with the systems and network infrastructure owned by third parties. All of the Utility's operational and technology systems and network infrastructure are vulnerable to disability or failures in the event of cyber and physical attacks. Cyberattacks are increasingly sophisticated and may include computer hacking, viruses, malware, social engineering, denial of service attacks, ransomware, destructive malware, or other means of disruption, destruction, or unauthorized access, acquisition or control. In addition, hardware, software, or applications the Utility develops or procures from third parties may contain defects in design or manufacture or other problems that could unexpectedly compromise information security. Physical attacks may include acts of sabotage, acts of war, acts of terrorism, or other physical acts. The Utility's operational and information technology systems and networks are deemed critical infrastructure, and any failure or decrease in their functionality could, among other things, cause harm to the public or employees, significantly disrupt operations,negatively impact the Utility's ability to generate, transport, deliver and store energy and gas, or otherwise operate in the most efficient manner or at all, undermine the Utility's performance of critical business functions, damage the Utility's assets or operations or those of third parties, and lead to reputational harm. As a result, such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, investigations, regulatory actions that could result in fines and penalties, and loss of customers, any of which could have a material effect on PG&E Corporation's and the Utility's financial condition and results of operations.

The Utility's systems, including its financial information, operational systems, advanced metering, and billing systems, require ongoing maintenance, modification, and updating, which can be costly and increase the risk of errors and malfunction. The Utility often relies on third-party vendors to host, maintain, modify, and update its systems and these third-party vendors could cease to exist, fail to establish adequate processes to protect the Utility's systems and information, or experience internal or external security incidents. Any incidents, disruptions or deficiencies in existing systems, or disruptions, delays or deficiencies in the modification of existing systems or implementation of new systems could result in increased costs, the inability to track or collect revenues, or diversion of management's and employees' attention and resources, or negatively affect the Utility's ability to maintain effective financial controls or timely file required regulatory reports. The Utility also could be subject to patent infringement claims arising from the use of third-party technology by the Utility or by a third-party vendor.

In addition, the Utility's information systems contain confidential information, including information about customers and employees. A data breach involving theft, improper disclosure, or other unauthorized access to or acquisition of confidential information could subject the Utility to penalties for violation of applicable privacy laws, claims by third parties, and enforcement actions by government agencies. It could also reduce the value of proprietary information, and harm the Utility's reputation.

The Utility and its third party vendors have been subject, and will likely continue to be subject, to attempts to gain unauthorized access to the Utility's information technology systems, or confidential data, or to disrupt the Utility's operations. None of these attempts or breaches has individually or in the aggregate resulted in a security incident with a material impact on PG&E Corporation's and the Utility's financial condition and results of operations. Despite implementation of security and control measures, there can be no assurance that the Utility will be able to prevent the unauthorized access to its systems, infrastructure, or data, or the disruption of its operations, either of which could materially affect PG&E Corporation's and the Utility's financial condition and results of operations.

While the Utility maintains cyber liability insurance that covers certain damages caused by cyber incidents, there is no guarantee that adequate insurance will continue to be available at rates the Utility believes are reasonable or that the costs of responding to and recovering from a cyber incident will be covered by insurance or recoverable in rates.

The operation and decommissioning of the Utility’s nuclear power plants expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements change or the plant ceases operations before the licenses expire.

The operation of the Utility’s nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation’s and the Utility’s financial results. In addition, the Utility may be required under federal law to pay up to $255 million of liabilities arising out of each nuclear incident occurring not only at the Utility’s Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 13 of the Notes to the Consolidated Financial Statements in the 2015 Form 10-K.)

On June 20, 2016, the Utility entered into a proposal to retire Diablo Canyon power plant at the expiration of its current operating licenses in 2024 and 2025, subject to certain regulatory approvals. However, the Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation. As a result, operations at the Utility’s two nuclear generation units at Diablo Canyon could cease before the licenses expire in 2024 and 2025. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge could have a material effect on PG&E Corporation and the Utility’s financial results.

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. (See “Regulatory Environment” in Item 1. Business in the 2015 Form 10-K.) If the Utility were unable to recover these costs, PG&E Corporation’s and the Utility’s financial results could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon before the licenses expire in 2024 and 2025. At June 30, 2016, the Utility’s unrecovered investment in Diablo Canyon was $2.3 billion.

At the state level, the California Water Board has adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. If the California Water Board requires the installation of cooling towers that the Utility believes are not technically or economically feasible, the Utility may be forced to cease operations at Diablo Canyon and may incur a material charge. If the Utility obtains contingent approvals referred to herein that will result in retiring Diablo Canyon at the end of the current NRC operating licenses, the Utility will not be required to install cooling towers or implement alternative measures in order to comply with the California State Water Board Once-Through Cooling Water Policy, thus eliminating the risk of regulatory uncertainty regarding the measures that could have been imposed on the Utility or of incurring a material charge related thereto. Even if the Utility is ultimately not required to install cooling towers, under the State Water Board's interim mitigation measures applicable to Diablo Canyon's operations prior to 2025, starting in 2016, it will be required to make payments to the California Coastal Conservancy to fund various environmental mitigation projects, that the Utility does not expect to exceed $5 million per year.

On June 28, 2016 the California State Lands Commission approved an extension of the Utility's leases of coastal land occupied by the water intake and discharge structures for the nuclear generation units at Diablo Canyon, to run concurrently with Diablo Canyon's current operating licenses. The Utility will be required to obtain an additional lease extension from the State Lands Commission to cover the period of time necessary to decommission the facility. The State Lands Commission and California Coastal Commission will evaluate appropriate environmental mitigation and development conditions associated with the decommissioning project, the costs of which could be substantial.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. (See Note 2: Summary of Significant Accounting Policies – Asset Retirement Obligations of the Notes to the Consolidated Financial Statement in Item 8.) The CPUC authorizes the Utility to recover its estimated costs to decommission its nuclear facilities through nuclear decommissioning charges that are collected from customers and held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. If the Utility's actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation's and the Utility's financial results could be materially affected.

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

During the quarter ended June 30, 2016, PG&E Corporation made equity contributions totaling $215 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 June 30, 2016.

Issuer Purchases of Equity Securities

During the quarter ended June 30, 2016, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended June 30, 2016, 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 six months ended June 30, 2016 was 1.23. The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the six months ended June 30, 2016 was 1.21. The statement of the foregoing ratios, together with the statements of the computation of the foregoing ratios filed as Exhibits 12.1 and 12.2 hereto, are included herein for the purpose of incorporating such information and Exhibits into the Utility's Registration Statement No. 333-193879.

PG&E Corporation's earnings to fixed charges ratio for the six months ended June 30, 2016 was 1.21. The statement of the foregoing ratio, together with the statement of the computation of the foregoing ratio filed as Exhibit 12.3 hereto, is included herein for the purpose of incorporating such information and Exhibit into PG&E Corporation's Registration Statement No. 333-193880.

ITEM 6. EXHIBITS

*10.1	Form of Restricted Stock Unit Agreement for 2016 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan
*10.2	Letter regarding Compensation Agreement between Pacific Gas and Electric Company and David Thomason dated May 24, 2016
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
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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.

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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

/s/ JASON P. WELLS
Jason P. Wells
Senior Vice President and Chief Financial Officer
(duly authorized officer and principal financial officer)

PACIFIC GAS AND ELECTRIC COMPANY

/s/ DAVID S. THOMASON
David S. Thomason

Vice President, Chief Financial Officer and Controller

(duly authorized officer and principal financial officer)

Dated: July 28, 2016

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