PG&E Corp
Form 10-Q
May 04, 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 March 31,2016

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 April 19,2016:	
PG&E Corporation:	496,042,305
Pacific Gas and Electric Company:	264,374,809

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

FOR THE QUARTERLY PERIOD ENDEDMARCH 31,2016

TABLE OF CONTENTS

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's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2015
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
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
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
GRC	general rate case
GT&S	gas transmission and storage
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
PSEP	pipeline safety enhancement plan
Regional Board	California Regional Water Control Board, Lahontan Region
SEC	U.S. Securities and Exchange Commission
SED	Safety and Enforcement Division of the CPUC, formerly known as the Consumer Protection and Safety Division or the CPSD
TO	transmission owner
TURN	The Utility Reform Network

Utility	Pacific Gas and Electric Company
VIE(s)	variable interest entity(ies)

3

PART I. FINANCIAL INFORMATION

ITEM 1. CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

PG&E CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited) Three Months Ended March 31,	
(in millions, except per share amounts)	2016	2015
Operating Revenues		
Electric	$3,131	$3,013
Natural gas	843	886
Total operating revenues	3,974	3,899
Operating Expenses		
Cost of electricity	950	1,000
Cost of natural gas	222	274
Operating and maintenance	2,010	1,923
Depreciation, amortization, and decommissioning	697	631
Total operating expenses	3,879	3,828
Operating Income	95	71
Interest income	4	1
Interest expense	(203)	(189)
Other income, net	27	58
Loss Before Income Taxes	(77)	(59)
Income tax benefit	(187)	(93)
Net Income	110	34
Preferred stock dividend requirement of subsidiary	3	3
Income Available for Common Shareholders	$107	$31
Weighted Average Common Shares Outstanding, Basic	493	477
Weighted Average Common Shares Outstanding, Diluted	495	481
Net Earnings Per Common Share, Basic	$0.22	$0.06
Net Earnings Per Common Share, Diluted	$0.22	$0.06
Dividends Declared Per Common Share	$0.46	$0.46

See accompanying Notes to the Condensed Consolidated Financial Statements.

4

PG&E CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited) Three Months Ended March 31,	
(in millions)	2016	2015
Net Income	$110	34
Other Comprehensive Income		
Pension and other postretirement benefit plans obligations		
(net of taxes of $0 and $0, at respective dates)	-	-
Net change in investments		
(net of taxes of $0 and $12, at respective dates)	-	(17)
Total other comprehensive income (loss)	-	(17)
Comprehensive Income	110	17
Preferred stock dividend requirement of subsidiary	3	3
Comprehensive Income Attributable to Common Shareholders	$107	14

See accompanying Notes to the Condensed Consolidated Financial Statements.

5

PG&E CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions)	March 31, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	$142	$123
Restricted cash	234	234
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $55 and $54 at respective dates)	1,010	1,106
Accrued unbilled revenue	685	855
Regulatory balancing accounts	1,721	1,760
Other	328	286
Regulatory assets	504	517
Inventories:		
Gas stored underground and fuel oil	109	126
Materials and supplies	344	313
Income taxes receivable	230	155
Other	327	338
Total current assets	5,634	5,813
Property, Plant, and Equipment		
Electric	49,974	48,532
Gas	16,982	16,749
Construction work in progress	2,148	2,059
Other	2	2
Total property, plant, and equipment	69,106	67,342
Accumulated depreciation	(21,062)	(20,619)
Net property, plant, and equipment	48,044	46,723
Other Noncurrent Assets		
Regulatory assets	7,130	7,029
Nuclear decommissioning trusts	2,516	2,470
Income taxes receivable	153	135
Other	1,173	1,064
Total other noncurrent assets	10,972	10,698
TOTAL ASSETS	$64,650	$63,234

See accompanying Notes to the Condensed Consolidated Financial Statements.

6

PG&E CORPORATION

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions, except share amounts)	March 31, 2016	December 31, 2015
LIABILITIES AND EQUITY		
Current Liabilities		
Short-term borrowings	$693	$1,019
Long-term debt, classified as current	160	160
Accounts payable:		
Trade creditors	1,062	1,414
Regulatory balancing accounts	704	715
Other	598	398
Disputed claims and customer refunds	457	454
Interest payable	145	206
Other	2,155	1,997
Total current liabilities	5,974	6,363
Noncurrent Liabilities		
Long-term debt	16,522	15,925
Regulatory liabilities	6,486	6,321
Pension and other postretirement benefits	2,629	2,622
Asset retirement obligations	4,480	3,643
Deferred income taxes	9,323	9,206
Other	2,372	2,326
Total noncurrent liabilities	41,812	40,043
Commitments and Contingencies (Note 9)		
Equity		
Shareholders' Equity		
Common stock, no par value, authorized 800,000,000 shares;		
495,606,702 and 492,025,443 shares outstanding at respective dates	11,440	11,282
Reinvested earnings	5,179	5,301
Accumulated other comprehensive loss	(7)	(7)
Total shareholders' equity	16,612	16,576
Noncontrolling Interest - Preferred Stock of Subsidiary	252	252
Total equity	16,864	16,828
TOTAL LIABILITIES AND EQUITY	$64,650	$63,234

See accompanying Notes to the Condensed Consolidated Financial Statements.

7

PG&E CORPORATION

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Three Months Ended March 31,			
(in millions)	2016		2015	
Cash Flows from Operating Activities				
Net income	$	110	$	34
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, amortization, and decommissioning		697		631
Allowance for equity funds used during construction		(27)		(28)
Deferred income taxes and tax credits, net		117		113
Disallowed capital expenditures		87		53
Other		73		52
Effect of changes in operating assets and liabilities:				
Accounts receivable		210		236
Inventories		(14)		58
Accounts payable		(65)		(46)
Income taxes receivable/payable		(75)		3
Other current assets and liabilities		146		(114)
Regulatory assets, liabilities, and balancing accounts, net		(87)		195
Other noncurrent assets and liabilities		(117)		(107)
Net cash provided by operating activities		1,055		1,080
Cash Flows from Investing Activities				
Capital expenditures		(1,229)		(1,191)
Proceeds from sales and maturities of nuclear decommissioning trust investments		439		417

Purchases of nuclear decommissioning trust investments		(463)		(505)
Other		3		7
Net cash used in investing activities		(1,250)		(1,272)
Cash Flows from Financing Activities				
Net issuances (repayments) of commercial paper, net of discount of $1 in 2016		(577)		223
Short-term debt financing		250		-
Proceeds from issuance of long-term debt, net of discount and issuance costs of $6 in 2016		594		-
Common stock issued		146		151
Common stock dividends paid		(219)		(211)
Other		20		23
Net cash provided by financing activities		214		186
Net change in cash and cash equivalents		19		(6)
Cash and cash equivalents at January 1		123		151
Cash and cash equivalents at March 31	$	142	$	145

8

Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(242)	$(216)
Supplemental disclosures of noncash investing and financing activities		
Common stock dividends declared but not yet paid	$226	$218
Capital expenditures financed through accounts payable	373	217
Noncash common stock issuances	6	5

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF INCOME

	(Unaudited) Three Months Ended March 31,	
(in millions)	2016	2015
Operating Revenues		
Electric	$3,132	$3,014
Natural gas	843	886
Total operating revenues	3,975	3,900
Operating Expenses		
Cost of electricity	950	1,000
Cost of natural gas	222	274
Operating and maintenance	2,011	1,923
Depreciation, amortization, and decommissioning	696	631
Total operating expenses	3,879	3,828
Operating Income	96	72
Interest income	4	1
Interest expense	(201)	(187)
Other income, net	24	26
Loss Before Income Taxes	(77)	(88)
Income tax benefit	(185)	(92)
Net Income	108	4
Preferred stock dividend requirement	3	3
Income Available for Common Stock	$105	$1

See accompanying Notes to the Condensed Consolidated Financial Statements.

10

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	(Unaudited) Three Months Ended March 31,	
(in millions)	2016	2015
Net Income	$ 108	4
Other Comprehensive Income		
Pension and other postretirement benefit plans obligations		
(net of taxes of $0 and $0, at respective dates)	-	-
Total other comprehensive income (loss)	-	-
Comprehensive Income	$ 108	4

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited) Balance At	
(in millions)	March 31, 2016	December 31, 2015
ASSETS		
Current Assets		
Cash and cash equivalents	$44	$59
Restricted cash	234	234
Accounts receivable:		
Customers (net of allowance for doubtful accounts of $55 and $54 at respective dates)	1,010	1,106
Accrued unbilled revenue	685	855
Regulatory balancing accounts	1,721	1,760
Other	353	284
Regulatory assets	504	517
Inventories:		
Gas stored underground and fuel oil	109	126
Materials and supplies	344	313
Income taxes receivable	204	130
Other	327	338
Total current assets	5,535	5,722
Property, Plant, and Equipment		
Electric	49,974	48,532
Gas	16,982	16,749
Construction work in progress	2,148	2,059
Total property, plant, and equipment	69,104	67,340
Accumulated depreciation	(21,060)	(20,617)
Net property, plant, and equipment	48,044	46,723
Other Noncurrent Assets		
Regulatory assets	7,130	7,029
Nuclear decommissioning trusts	2,516	2,470
Income taxes receivable	153	135
Other	1,061	958
Total other noncurrent assets	10,860	10,592
TOTAL ASSETS	$64,439	$63,037

See accompanying Notes to the Condensed Consolidated Financial Statements.

12

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED BALANCE SHEETS

	(Unaudited)	
	Balance At	
(in millions, except share amounts)	March 31, 2016	December 31, 2015
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Short-term borrowings	$ 693	$ 1,019
Long-term debt, classified as current	160	160
Accounts payable:		
Trade creditors	1,062	1,414
Regulatory balancing accounts	704	715
Other	646	418
Disputed claims and customer refunds	457	454
Interest payable	144	203
Other	1,906	1,750
Total current liabilities	5,772	6,133
Noncurrent Liabilities		
Long-term debt	16,174	15,577
Regulatory liabilities	6,486	6,321
Pension and other postretirement benefits	2,540	2,534
Asset retirement obligations	4,480	3,643
Deferred income taxes	9,605	9,487
Other	2,331	2,282
Total noncurrent liabilities	41,616	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	7,280	7,215
Reinvested earnings	8,188	8,262
Accumulated other comprehensive income	3	3
Total shareholders' equity	17,051	17,060
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 64,439	$ 63,037

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	(Unaudited) Three Months Ended March 31,			
(in millions)	2016		2015	
Cash Flows from Operating Activities				
Net income	$	108	$	4
Adjustments to reconcile net income to net cash provided by operating activities:				
Depreciation, amortization, and decommissioning		696		631
Allowance for equity funds used during construction		(27)		(28)
Deferred income taxes and tax credits, net		118		112
Disallowed capital expenditures		87		53
Other		68		45
Effect of changes in operating assets and liabilities:				
Accounts receivable		183		215
Inventories		(14)		58
Accounts payable		(37)		26
Income taxes receivable/payable		(74)		2
Other current assets and liabilities		151		(123)
Regulatory assets, liabilities, and balancing accounts, net		(87)		195
Other noncurrent assets and liabilities		(109)		(89)
Net cash provided by operating activities		1,063		1,101
Cash Flows from Investing Activities				
Capital expenditures		(1,229)		(1,191)
Proceeds from sales and maturities of nuclear decommissioning trust investments		439		417
		(463)		(505)

Purchases of nuclear decommissioning trust investments				
Other		3		7
Net cash used in investing activities		(1,250)		(1,272)
Cash Flows from Financing Activities				
Net issuances (repayments) of commercial paper, net of discount of $1 in 2016		(577)		223
Short-term debt financing		250		-
Proceeds from issuance of long-term debt, net of discount and issuance costs of $6 in 2016		594		-
Preferred stock dividends paid		(3)		(3)
Common stock dividends paid		(179)		(179)
Equity contribution from PG&E Corporation		65		100
Other		22		25
Net cash provided by financing activities		172		166
Net change in cash and cash equivalents		(15)		(5)
Cash and cash equivalents at January 1		59		55
Cash and cash equivalents at March 31	$	44	$	50

14

Supplemental disclosures of cash flow information		
Cash received (paid) for:		
Interest, net of amounts capitalized	$(237)	$(211)
Supplemental disclosures of noncash investing and financing activities		
Capital expenditures financed through accounts payable	$373	$217

See accompanying Notes to the Condensed Consolidated Financial Statements.

15

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 March 31,2016, 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 March 31,2016, 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. 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. 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.

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 $3.3 billion at March 31, 2016, which includes an $818 million adjustment to reflect the increased cost estimates described above, and $2.5 billion at December 31, 2015. These estimates are based on the 2016 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.

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 months ended March 31, 2016 and 2015 were as follows:

	Pension Benefits		Other Benefits	
	Three Months Ended March 31,			
(in millions)	2016	2015	2016	2015
Service cost for benefits earned	$ 113	$ 119	$ 13	$ 13

Interest cost	179	168	19	18
Expected return on plan assets	(207)	(218)	(27)	(28)
Amortization of prior service cost	2	4	4	5
Amortization of net actuarial loss	6	3	1	1
Net periodic benefit cost	93	76	10	9
Regulatory account transfer (1)	(8)	9	-	-
Total	$ 85	$ 85	$ 10	$ 9

(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.

17

Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

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

(in millions, net of income tax)	Pension Benefits	Other Benefits	Total
	Three Months Ended March 31, 2016		
Beginning balance	$ (23)	$ 16	$ (7)
Amounts reclassified from other comprehensive income: (1)			
Amortization of prior service cost			
(net of taxes of $1 and $2, respectively)	1	2	3
Amortization of net actuarial loss			
(net of taxes of $2 and $0, respectively)	4	1	5
Regulatory account transfer			
(net of taxes of $3 and $2, respectively)	(5)	(3)	(8)
Net current period other comprehensive 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
	Three Months Ended March 31, 2015			
Beginning balance	$(21)	15	17	11
Amounts reclassified from other comprehensive income:				
Amortization of prior service cost				
(net of taxes of $2, $2, and $0, respectively) (1)	2	3	-	5
Amortization of net actuarial loss				
(net of taxes of $1, $0, and $0, respectively) (1)	2	-	-	2
Regulatory account transfer				
(net of taxes of $3, $2, and $0, respectively) (1)	(4)	(3)	-	(7)
Change in investments				
(net of taxes of $0, $0, and $12, respectively)	-	-	(17)	(17)
Net current period other comprehensive loss	-	-	(17)	(17)
Ending balance	$(21)	$ 15	$ -	$ (6)

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

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.

18

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 are currently evaluating the impact the guidance will have on their 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 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 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 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)	March 31, 2016	December 31, 2015
Pension benefits	$2,414	$ 2,414
Deferred income taxes	3,265	3,054
Utility retained generation	399	411
Environmental Compliance Costs	683	748
Price risk management	134	138
Unamortized loss, net of gain, on reacquired debt	90	94
Other	145	170
Total long-term regulatory assets	$7,130	$ 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	
	March 31,	December 31,
(in millions)	2016	2015
Cost of removal obligations	$4,717	$ 4,605
Recoveries in excess of asset retirement obligations	645	631
Public purpose programs	620	600
Other	504	485
Total long-term regulatory liabilities	$6,486	$ 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)	March 31, 2016	December 31, 2015
Electric distribution	$515	$ 380
Utility generation	225	122
Gas distribution	280	493
Energy procurement	87	262
Public purpose programs	149	155
Other	465	348
Total regulatory balancing accounts receivable	$1,721	$ 1,760

	Payable Balance at	
(in millions)	March 31, 2016	December 31, 2015
Energy procurement	$184	$ 112
Public purpose programs	212	244
Other	308	359
Total regulatory balancing accounts payable	$704	$ 715

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 March 31,2016:

(in millions)	Termination Date	Facility Limit		Letters of Credit Outstanding	Commercial Paper	Facility Availability
PG&E Corporation	April 2020	$300	(1)	$ -	$ -	$ 300
Utility	April 2020	3,000	(2)	33	443	2,524
Total revolving credit facilities		$3,300		$ 33	$ 443	$ 2,824

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

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 March 31,2016, 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 0.37% to 0.45%. At March 31, 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 0.34% to 0.38%. 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 three months ended March 31,2016were as follows:

(in millions)	PG&E Corporation Total Equity	Utility Total Shareholders' Equity
Balance at December 31, 2015	$ 16,828	$ 17,060
Comprehensive income	110	108
Equity contributions	-	65
Common stock issued	152	-

Share-based compensation	6	-
Common stock dividends declared	(229)	(179)
Preferred stock dividend requirement	-	(3)
Preferred stock dividend requirement of subsidiary	(3)	-
Balance at March 31, 2016	$ 16,864	$ 17,051

During the three months ended March 31, 2016, PG&E Corporation sold 1.3 million shares under the February 2015 equity distribution agreement for cash proceeds of $74 million, net of commissions paid of $1 million. As of March 31, 2016, the remaining gross sales available under this agreement were $350 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 threemonths ended March 31,2016, 2.3 million shares were issued for cash proceeds of $72 million under these plans.

22

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 March 31,	
(in millions, except per share amounts)	2016	2015
Income available for common shareholders	$107	$31
Weighted average common shares outstanding, basic	493	477
Add incremental shares from assumed conversions:		
Employee share-based compensation	2	4
Weighted average common shares outstanding, diluted	495	481
Total earnings per common share, diluted	$0.22	$0.06

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'sCondensed 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	March 31, 2016	December 31, 2015
Natural Gas (1) (MMBtus (2))	Forwards and Swaps	341,884,852	333,091,813
	Options	92,426,200	111,550,004
Electricity (Megawatt-hours)	Forwards and Swaps	3,580,205	3,663,512
	Congestion Revenue Rights (3)	198,499,963	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 March 31,2016, 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	$91	$ (5)	$ 12	$ 98
Other noncurrent assets – other	173	(5)	-	168
Current liabilities – other	(105)	5	46	(54)
Noncurrent liabilities – other	(139)	5	16	(118)
Net commodity risk	$20	$ -	$ 74	$ 94

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 March 31,	
(in millions)	2016	2015
Net unrealized gain (loss) - regulatory assets and liabilities (1)	$(7)	$ (52)
Realized loss - cost of electricity (2)	(29)	(7)
Realized loss - cost of natural gas (2)	(1)	(1)
Total commodity risk	$(37)	$ (60)

(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 March 31,2016, 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)	March 31, 2016	December 31, 2015
Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized	$ (9)	$ (2)
Collateral posting in the normal course of business related to these derivatives	7	-
Net position of derivative contracts/additional collateral posting requirements (1)	$ (2)	$ (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.

25

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 March 31, 2016				
(in millions)	Level 1	Level 2	Level 3	Netting (1)	Total
Assets:					
Short-term investments	$97	$-	$-	$ -	$97
Nuclear decommissioning trusts					
Short-term investments	25	-	-	-	25
Global equity securities	1,619	-	-	-	1,619
Fixed-income securities	682	508	-	-	1,190
Assets measured at NAV	-	-	-	-	13
Total nuclear decommissioning trusts (2)	2,326	508	-	-	2,847
Price risk management instruments (Note 7)					
Electricity	1	12	246	3	262
Gas	2	3	-	(1)	4
Total price risk management instruments	3	15	246	2	266
Rabbi trusts					
Fixed-income securities	-	58	-	-	58
Life insurance contracts	-	72	-	-	72
Total rabbi trusts	-	130	-	-	130
Long-term disability trust					
Short-term investments	8	-	-	-	8
Assets measured at NAV	-	-	-	-	147
Total long-term disability trust	8	-	-	-	155
Total assets	$2,434	$653	$246	$ 2	$3,495
Liabilities:					
Price risk management instruments (Note 7)					
Electricity	$67	$5	$171	$ (72)	$171
Gas	-	1	-	-	1
Total liabilities	$67	$6	$171	$ (72)	$172

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

(2) Represents amount before deducting $331 million, primarily related to deferred taxes on appreciation of investment value.

26

	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 three months ended March 31,2016 and 2015.

27

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.

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 US 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 financeand risk management functions collaborate to determine the appropriate fair value methodologies and classification for each derivative. Inputs used and the fair value of Level 3 instruments are reviewed period-over-period and compared with market conditions to determine reasonableness.

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 7 above.)

(in millions)	Fair Value at At March 31, 2016		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	Input	Range (1)
Congestion revenue rights	$246	$ 59	Market approach	CRR auction prices	$(23.81) - 8.76
Power purchase agreements	$-	$ 112	Discounted cash flow	Forward prices	$17.64 - 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 months ended March 31, 2016 and 2015:

	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)	(14)	(27)
Asset (liability) balance as of March 31	$ 75	$ 42

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

Financial Instruments

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

- The fair values of cash, restricted cash, net accounts receivable, short-term borrowings, accounts payable, customer deposits, and the Utility's variable rate pollution control bond loan agreements approximate their carrying values at March 31,2016 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 March 31,2016 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):

(in millions)	At March 31, 2016 Carrying Amount	At March 31, 2016 Level 2 Fair Value	At December 31, 2015 Carrying Amount	At December 31, 2015 Level 2 Fair Value
PG&E Corporation	$350	$356	$350	$354
Utility	15,412	17,823	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 March 31, 2016				
Nuclear decommissioning trusts				
Short-term investments	$ 25	$-	$-	$25
Global equity securities	603	1,038	(9)	1,632
Fixed-income securities	1,113	81	(4)	1,190
Total (1)	$ 1,741	$1,119	$(13)	$2,847
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 $331 million and $314 million at March 31,2016 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)	March 31, 2016
Less than 1 year	$26
1–5 years	409
5–10 years	251
More than 10 years	504
Total maturities of fixed-income securities	$1,190

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

	Three Months Ended	
	March 31, 2016	March 31, 2015
(in millions)		
Proceeds from sales and maturities of nuclear decommissioning trust investments	$439	417
Gross realized gains on sales of securities held as available-for-sale	5	35
Gross realized losses on sales of securities held as available-for-sale	(2)	(3)

NOTE 9: CONTINGENCIES AND COMMITMENTS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. The Utility also has substantial financial commitments in connection with agreements entered into to support its operating activities. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows also may be affected by the outcome of the following matters.

Enforcement and Litigation Matters

CPUC Matters

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 April 18, 2016, the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility filed a joint Meet and Confer Process Report in advance of the prehearing conference that was held on April 20, 2016. The report included the proposed scope of the proceeding, including the number of communications at issue, a procedure for moving undisputed facts into the evidentiary record, a diligence process for providing additional factual information, and a procedural schedule. Subject to the CPUC's approval, the parties have agreed that the scope of this proceeding may include a total of 159 communications (the 46 communications already included in the OII and 113 additional communications). The parties also recommended briefing on whether an additional 21 communications should be included in the proceeding. The Utility is expecting a ruling on these proposals in the second quarter of 2016.

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, and whether the CPUC will consider additional communications in the OII, including those identified in a motion filed on December 1, 2015, by the City of San Bruno in the 2015 GT&S rate case. It is also uncertain whether the CPUC will take additional action in any of the proceedings in which the Utility has self-reported communications that may have violated the CPUC's ex parte rules.

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 requires the Utility to show cause why (1) the CPUC should not find that the Utility violated provisions of the California Public Utilities Code, CPUC general orders or decisions, other rules, or requirements, and/or engaged in unreasonable and/or imprudent practices related to these matters, and (2) the CPUC should not impose penalties, and/or any other forms of relief, if any violations are found. In particular, the order cites the SED's investigative reports alleging that the Utility violated rules regarding safety record-keeping in connection with six natural gas distribution incidents, including the natural gas explosion that occurred in Carmel, California on March 3, 2014.

On September 30, 2015, the SED submitted its supplemental testimony, which included incidents allegedly related to record-keeping that had not been identified in the initial order, and also asserted violations related to the Utility's pre-excavation location and marking practices, causal evaluation practices, and compliance with regulations governing pressure validation for certain distribution facilities.

On February 26, 2016, the Utility, the SED, TURN, and the City of Carmel, California("Carmel") filed their opening briefs. In its brief, the SED cited alleged record-keeping violations related to various natural gas distribution incidents, the Utility's pre-excavation location and marking practices, causal evaluation practices, and compliance with regulations governing pressure validation for certain distribution facilities. The SED recommended that the CPUC impose a fine on the Utility of approximately $112 million for these alleged violations. The SED also recommended that the CPUC require the Utility to undertake various remedial actions with respect to its gas distribution system records and facilities and that the Utility be prohibited from recovering remedial-related costs from customers. Carmel recommended that the CPUC impose penalties on the Utility of up to approximately $652 million, including approximately $137 million for the natural gas explosion that occurred in Carmel on March 3, 2014 (for which the Utility has previously paid a CPUC-imposed fine of $10.85 million). Carmel also recommended various remedial measures. TURN recommended that the Utility be required to undertake remedial actions, fund annual SED audits of the Utility's record-keeping practices for a period of ten years, and promptly correct any deficiencies identified in those audits.

On April 1, 2016, the Utility filed its reply brief in which the Utility indicated that it did not agree that any penalty was appropriate, but if the CPUC determined that a penalty should be imposed, such penalty should not exceed $33.6 million. The Utility recommended that such penalty, if imposed, should be invested in the safety of the Utility's gas distribution system, for example for implementation of certain remedial measures. The Utility expects that the presiding officer's decision will be issued within 60 days of the April 1, 2016 filing. Unless any party files an appeal of the presiding officer's decision or a CPUC Commissioner requests a CPUC review of the presiding officer's decision within 30 days, the decision will become final. The CPUC has the authority to extend the deadlines indicated above.

PG&E Corporation and the Utility believe it is probable that the CPUC will impose penalties on the Utility in the form of fines or other remedies, including possible future unrecoverable costs to implement operational remedies. Remedies would be recorded in the period the expense is incurred and fines would be recorded when considered probable and their amount or range can be reasonably estimated. The Utility is unable to determine the form or amount of penalties or reasonably estimate the amount or range of future charges that could be incurred given the CPUC's discretion in imposing fines and other remedies.

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. Although the trial previously had been scheduled to begin on April 26, 2016, the court vacated the trial date and no new trial date has been set. The court stated that it will set a new trial date in due course.

The maximum statutory fine for each felony count is $500,000, for total potential fines of $6.5 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 are not considered to be probable.

Other Federal Matters

The Utility was informed that the U.S. Attorney's Office was investigating a natural gas explosion that occurred in Carmel, California on March 3, 2014. The U.S. Attorney's Office in San Francisco also continues to investigate matters relating to the indicted case discussed above. It is uncertain whether any additional charges will be brought against the Utility.

Capital Expenditures Relating to Pipeline Safety Enhancement Plan

The CPUC has authorized the Utility to collect $766 million for recovery of PSEP capital costs. As of March 31, 2016, the Utility has spent $1.3 billion on PSEP-related capital costs, of which $665 million was written off 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.

Penalty Decision's Disallowance of Natural Gas Capital Spend

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. In August 2015, the Utility paid the $300 million fine.

For the three months ended March 31, 2016, the Utility recorded additional charges in operating and maintenance expenses in the Condensed Consolidated Statements of Income of $87 million, as a result of the Penalty Decision. The cumulative charges at March 31, 2016, and the additional future charges to reach the $1.6 billion total are shown in the following table:

(in millions)	Three Months Ended March 31, 2016	Cumulative Charges March 31, 2016	Future Charges and Costs	Total Amount
Fine paid to the state	$ -	$ 300	$ -	$ 300
Customer bill credit	-	400	-	400
Charge for disallowed capital (1)	87	494	195	689
Disallowed revenue for pipeline safety expenses (2)	-	-	161	161
CPUC estimated cost of other remedies (3)	-	-	-	50
Total Penalty Decision fines and remedies	$ 87	$ 1,194	$ 356	$ 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 decision to be issued in the Utility's 2015 GT&S rate case. The Penalty Decision requires that at least $689 million of the $850 million cost disallowance be allocated to capital expenditures. The Utility estimates that approximately $494 million of cumulative capital spending is probable of disallowance, subject to adjustment based on the final 2015 GT&S rate case decision.

(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 and does not reflect the Utility's remedy-related costs already incurred nor the Utility's estimated future remedy-related costs. These costs are being expensed as incurred.

Other Legal and Regulatory Contingencies

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. 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.

Investigation of 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 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.

In connection with the Butte fire, approximately 32 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 1,300 individual plaintiffs and their insurance companies. In response to plaintiffs' and the Utility's requests, the California Judicial Council has authorized the coordination of all cases in the Superior Court of California, Sacramento County. 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 number of complaints may increase in the future. An initial case management conference was held on April 22, 2016 and the next case management conference is currently scheduled for May 24, 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 estimated 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. At March 31, 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 this amount, 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.

The Utility has insurance coverage for third party claims. If the amount of insurance is insufficient to cover the Utility's liability resulting from the Butte fire, or if insurance is otherwise unavailable, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected.

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.

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. In the re-opened proceeding, the CPUC will evaluate whether the incentive amounts awarded to the IOUs were just and reasonable, and whether any refunds are due.

On March 18, 2016, TURN and ORA submitted a joint proposal to require a refund of incentive awards that TURN and ORA argue were not calculated in accordance with the ratemaking mechanism rules and procedures the CPUC had previously adopted. TURN and ORA contended that the CPUC should order the Utility to refund $104 million, the entire incentive earnings award, plus interest, to customers as either (1) a revenue credit to customers' distribution and gas transportation accounts or (2) as a line item to the customers' first monthly bill following the issuance of a CPUC decision.

Additionally, on March 18, 2016, the IOUs submitted their proposals requesting that the CPUC reaffirm its prior decisions. The IOUs asserted that, given the many unresolved disputes about the data in the Energy Division's 2010 Evaluation Report, the CPUC appropriately used different data to calculate the awards. The IOUs noted that under the incentive ratemaking mechanism, any refunds of prior incentive earnings should be deducted from future incentive earnings claims.

On April 8, 2016, the IOUs, TURN and ORA filed comments on the proposals, in which the parties reiterated their requests. The Utility currently expects that evidentiary hearings, if ordered by the CPUC, would be held in July 2016. It is uncertain how the CPUC will resolve this matter and when the CPUC will issue a decision.

PG&E Corporation and the Utility believe it is reasonably possible that the Utility will be required to refund amounts previously awarded or incur other obligations related to this matter, but they are unable to reasonably estimate the amount of such refunds or other obligations. If the Utility were required to make a refund as TURN and ORA propose, PG&E Corporation's and the Utility's financial results would be affected by the amount of any refund-related charges.

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 Utility charging rates not authorized by the CPUC. On March 14, 2016, the assigned ALJ issued an additional ruling that (1) acknowledged that utilities might not be able to follow the exact "glidepath" set forth in the decision because it had been based on forecast data and (2) indicated a new process to be followed before the CPUC if the new rates do not exactly match the "glidepath." On March 24, 2016, the Utility temporarily reverted back to billing customers based on rates generally similar to those in place prior to March 1, 2016. Also, on March 24, 2016, the Utility filed an additional advice letter proposing a new, three-tiered rate structure. The proposed new rate structure is subject to the CPUC approval. On April 20, 2016, the Energy Division of the CPUC issued a draft resolution that approves the Utility's proposed solution, but does not address the ruling to show cause. The Utility believes it is reasonably possible it may be subject to penalties or shareholder reparations for charging rates not authorized by the CPUC between March 1, 2016 and March 24, 2016. The Utility is unable to determine the form or amount of penalties or reasonably estimate the amount or range of future charges that could be incurred.

Other Contingencies

Accruals for other legal and regulatory contingencies (excluding amounts related to the contingencies discussed above under “Enforcement and Litigation Matters” and “Other Legal and Regulatory Contingencies”) totaled $55 million at March 31, 2016 and $63 million at December 31, 2015. These amounts are included in other current liabilities in the Condensed Consolidated Balance Sheets. The resolution of these matters is not expected to have a material impact on PG&E Corporation’s and the Utility’s financial condition, results of operations, or cash flows.

Environmental Remediation Contingencies

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

	Balance at	
(in millions)	March 31, 2016	December 31, 2015
Topock natural gas compressor station (1)	$302	$ 300
Hinkley natural gas compressor station (1)	140	140
Former manufactured gas plant sites owned by the Utility or third parties	283	271
Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites	136	164
Fossil fuel-fired generation facilities and sites	103	94
Total environmental remediation liability	$964	$ 969

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

36

At March 31,2016, the Utility expected to recover $680 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 March 31,2016reflects 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 California Department of Toxic Substances Control and the U.S. Department of the Interior. 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 July 2016. After the DTSC considers public comments that may be made, the DTSC is expected to issue a final environmental impact report in December 2016. After the Utility modifies its design in response to the final report, the Utility plans to seek approval to begin construction of the new in-situ treatment system in early 2017.

The Utility's environmental remediation liability at March 31, 2016reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to be performed to implement the final groundwater remedy and the Utility's required time frame for remediation. Future changes in cost estimates and the assumptions on which they are based may have a material impact on future financial condition and cash flows.

Reasonably Possible Environmental Contingencies

Although the Utility has provided for known environmental obligations that are probable and reasonably estimable, the Utility's undiscounted future costs could increase to as much as $1.9billion (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, as of April 1, 2016, 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, as of April 1, 2016. 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.

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 three months ended March 31, 2016. However, on April 14, 2016, PG&E filed a Joint Offer of Settlement with the FERC requesting approval of a $256 million settlement agreement which, if approved, would result in a reduction to PG&E's net disputed claims liability.

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 ofMarch 31,2016, it is reasonably possible that unrecognized tax benefits will decrease by approximately $70 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 hadundiscounted 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 three months ended March 31, 2016.

38

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

OVERVIEW

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers.

The Utility is regulated primarily by the CPUC and the FERC. The CPUC has jurisdiction over the rates and terms and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility also is subject to the jurisdiction of other federal, state, and local governmental agencies.

This is a combined quarterly report of PG&E Corporation and the Utility and should be read in conjunction with each company's separate Condensed Consolidated Financial Statements and the Notes to the Condensed Consolidated Financial Statements included in this quarterly report. It should also be read in conjunction with the 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. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short- and long-term operating plans, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance. Earnings from operations are not a substitute or alternative for GAAP measures such as income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

	Three Months Ended March 31,	
(in millions, except per share amounts)	Earnings	EPS (Diluted)
Income Available for Common Shareholders - March 31, 2015	$31	$ 0.06
Fines and penalties (1)	369	0.77
Pipeline-related expenses (2)	10	0.02
Legal and regulatory related expenses (2)	8	0.02
Earnings from Operations -March 31, 2015 (3)	$418	$ 0.87
Growth in rate base earnings	26	0.05
Timing of taxes (4)	(40)	(0.08)
Gain on disposition of SolarCity stock (5)	(14)	(0.03)
Increase in shares outstanding	-	(0.03)
Miscellaneous	17	0.04
Earnings from Operations - March 31, 2016 (3)	$407	$ 0.82
Butte fire related expenses (6)	(226)	(0.45)
Fines and penalties (1)	(51)	(0.10)
Pipeline-related expenses (2)	(13)	(0.03)
Legal and regulatory related expenses (2)	(10)	(0.02)
Income Available for Common Shareholders - March 31, 2016	$107	$ 0.22

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

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

(3) "Earnings from operations" is not calculated in accordance with GAAP and excludes the items impacting comparability shown in Notes (1) and (2).

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

(5)Represents the gain recognized during the three months ended March 31, 2015. No comparable gain was recognized in 2016.

(6)For the three months ended March 31, 2016, the Utility incurred charges of $350 million, pre-tax, related to estimated property damages in connection with the Butte fire and $31 million, pre-tax, for Utility clean-up, repair, and legal costs associated with the Butte fire, for a total of $381 million, pre-tax.

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, the re-hearing of the 2006-2008 energy efficiency incentive awards, and the Butte fire. (See "Enforcement and Litigation Matters" in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- The Timing and Outcome of Ratemaking Proceedings. The 2015 GT&S rate case remains pending. The Utility requested that the CPUC authorize a $532 million increase in annual revenue requirements for gas transmission and storage operations beginning on January 1, 2015 with attrition increases in 2016 and 2017. Any revenue requirement increase that the CPUC may authorize would be retroactive to January 1, 2015 but would be recorded in the period a final decision is reached. (See "Regulatory Matters – 2015 Gas Transmission and Storage Rate Case" below for more information.) In February 2016, the Utility updated its 2017 GRC application to request that the CPUC authorize a revenue requirement increase of $333 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. (See "Regulatory Matters – 2017 General Rate Case" below for more information.) The CPUC's decisions in these cases are expected to be issued in 2016. 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. Whether the Utility is able to earn its authorized rate of return could be materially affected if the Utility's actual costs differ from the amounts authorized in the rate case decisions. In addition to incurring shareholder-funded 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. 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 "Enforcement and Litigation Matters" in 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 driven by legislative and regulatory initiatives relating to distributed generation resources, renewable energy requirements, and changes in the electric rate structure.

- The Amount and Timing of the Utility's Financing Needs. PG&E Corporation contributes equity to the Utility as needed to maintain the Utility's CPUC-authorized capital structure. For the three months ended March 31, 2016, PG&E Corporation issued $152 million of common stock and used $65 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 "Enforcement and Litigation Matters" 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.

41

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 “Cautionary Language Regarding Forward-Looking Statements” below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

RESULTS OF OPERATIONS

PG&E Corporation

The consolidated results of operations consist primarily of balances related to the Utility, which are discussed below. The following table provides a summary of net income available for common shareholders for the three months ended March 31,2016 and 2015:

	Three Months Ended March 31,	
(in millions)	2016	2015
Consolidated Total	$ 107	$ 31
PG&E Corporation	2	30
Utility	$ 105	$ 1

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

Utility

The table below shows certain items from the Utility's Condensed Consolidated Statements of Income for the threemonths ended March 31,2016 and 2015. The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings. In general, expenses the Utility is authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs), and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized(such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

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

The Utility’s operating results for the three months ended March 31, 2016 and 2015 reflect charges associated with the impact of the Penalty Decision. (See “Utility Revenues and Costs that Impacted Earnings” below.)

(in millions)	Three Months Ended March 31, 2016 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	Three Months Ended March 31, 2015 Revenues/Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility
Electric operating revenues	$1,933	$ 1,199	$3,132	$1,786	$ 1,228	$3,014
Natural gas operating revenues	523	320	843	506	380	886
Total operating revenues	2,456	1,519	3,975	2,292	1,608	3,900
Cost of electricity	-	950	950	-	1,000	1,000
Cost of natural gas	-	222	222	-	274	274
Operating and maintenance	1,664	347	2,011	1,589	334	1,923
Depreciation, amortization, and decommissioning	696	-	696	631	-	631
Total operating expenses	2,360	1,519	3,879	2,220	1,608	3,828
Operating income	96	-	96	72	-	72
Interest income (1)			4			1
Interest expense (1)			(201)			(187)
Other income, net (1)			24			26
Income (loss) before income taxes			(77)			(88)
Income tax benefit (1)			(185)			(92)
Net income			108			4
Preferred stock dividend requirement (1)			3			3
Income Available for Common Stock			$105			$1

(1) These items impacted earnings for the three months endedMarch 31,2016 and 2015.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility’s operating results for the three months ended March 31,2016 and 2015, focusing on revenues and expenses that impacted earnings for these periods.

Operating Revenues

The Utility's electric and natural gas operating revenues that impacted earnings increased by $164 million, or 7%,in the three months ended March 31, 2016, compared to the same period in 2015 primarily due additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO rate case.

The Utility has requested the CPUC authorize an increase to its revenue requirements for 2015, 2016, and 2017 in its GT&S rate case. It is unlikely that the Utility will be able to recognize an increase in its GT&S revenue until the second half 2016 or a later period during which a final decision is issued. The CPUC's decision in this case is expected to be issued in 2016. (See "Ratemaking Proceedings" below.)

Operating and Maintenance

The Utility's operating and maintenance expenses that impacted earnings increased by $75million, or 5%,in the three months ended March 31, 2016 compared to the same period in 2015 primarily due to $381 million in charges related to the Butte Fire,approximately $90 million ofother operating expenses, $34 million of higher disallowed capital charges related to the Penalty Decision, and $30 million of higher benefit-related expenses. This increase was offset by $500 million in charges associated with the Penalty Decision for fines and customer refunds incurred in the first quarter of 2015 with no corresponding charges in 2016. (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.)

Depreciation, Amortization, and Decommissioning

The Utility's depreciation, amortization, and decommissioning expenses increased by $65 million, or 10% in the three months ended March 31, 2016 compared to the same period in 2015. This increase was primarily due to the impact of capital additions and higher depreciation rates as authorized by CPUC in the 2014 GRC decision, which was first reflected in the third quarter of 2014, and by the FERC in the TO rate case.

Interest Income, Interest Expense, and Other Income, Net

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

Income Tax Benefit

The income tax benefit increased by $93 million, or 101%in the three months ended March 31, 2016 as compared to the same period in 2015. The effective tax rates for the three months ended March 31, 2016 and 2015 were 241% and 105%, respectively. These increases were primarily driven by benefits resulting from various tax audit results in the three months ended March 31, 2016 with no comparable amounts in the three months ended March 31, 2015 and the tax impact of a non-deductible penalty accrued in the three months ended March 31, 2015 with no comparable amount in the three months ended March 31, 2016.

Utility Revenues and Costs that did not Impact Earnings

Fluctuations in revenues that did not impact earnings are primarily driven by procurement costs. See below for more detail.

Cost of Electricity

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

	Three Months Ended March 31,	
(in millions)	2016	2015
Cost of purchased power	$886	$922
Fuel used in own generation facilities	64	78
Total cost of electricity	$950	$1,000
Average cost of purchased power per kWh (1)	$0.104	$0.099
Total purchased power (in millions of kWh) (2)	8,539	9,291

(1)Average cost of purchased power for the three months ended March 31, 2016 increased compared to the same period in 2015 primarily due to higher percentage of renewable energy resources. This increase was partially offset by lower market prices for natural gas.

(2) The decrease in purchased power resulted from an increase in generation from the Utility's own generation facilities. Hydroelectric and nuclear generation increased during the three months ended March 31, 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.

	Three Months Ended March 31,	
(in millions)	2016	2015
Cost of natural gas sold	$181	$235
Transportation cost of natural gas sold	41	39
Total cost of natural gas	$222	$274
Average cost per Mcf (1) of natural gas sold (2)	$2.26	$3.26
Total natural gas sold (in millions of Mcf) (1)	80	72

(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 months ended March 31, 2016 compared to the same period 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 debt financing costs. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure consisting of 52% equity and 48% debt and preferred stock. The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's ability to fund operations, make scheduled principal and interest payments, fund equity contributions to the Utility, and pay dividends, primarily depends on the level of cash distributions received from the Utility and PG&E Corporation's access to the capital and credit markets. PG&E Corporation has material stand-alone cash flows related to the issuance of equity and long-term debt, dividend payments, and borrowings and repayments under its revolving credit facility. PG&E Corporation relies on short-term debt, including commercial paper, to fund temporary financing needs.

PG&E Corporation's equity contributions to the Utility are funded primarily through common stock issuances. PG&E Corporation forecasts that it will issue between $600 million and $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 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 months ended March 31, 2016, PG&E Corporation sold 1.3 million shares under its February 2015 equity distribution agreement for cash proceeds of $74 million, net of commissions paid of $1 million. As of March 31, 2016, the remaining gross sales available under this agreement were $350 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 three months ended March 31, 2016, 2.3 million shares were issued for cash proceeds of $72 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 three months ended March 31, 2016, PG&E Corporation made equity contributions to the Utility of $65 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

At March 31, 2016, PG&E Corporation and the Utility had $300 million and $2.5 billion available under their respective $300 million and $3.0 billion revolving credit facilities. (See Note 4 of the Notes to the Condensed Consolidated Financial Statements.)

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. At March 31, 2016, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 51% and 50%, 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 March 31, 2016, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

In February 2016, the Board of Directors of PG&E Corporation declared quarterly dividends of $0.455 per share, totaling $226 million, of which approximately $221 million was paid on April 15, 2016, to shareholders of record on March 31, 2016.

In February 2016, the Board of Directors of the Utility declared a common stock dividend of $179 million that was paid to PG&E Corporation on February 19, 2016.

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

Utility Cash Flows

The Utility's cash flows were as follows:

(in millions)	Three Months Ended March 31, 2016 2016	2015
Net cash provided by operating activities	$1,063	$1,101
Net cash used in investing activities	(1,250)	(1,272)
Net cash provided by financing activities	172	166
Net change in cash and cash equivalents	$(15)	$(5)

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 three months ended March 31, 2016, net cash provided by operating activities decreased by $38 million compared to the same period in 2015. This decrease was primarily due to fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections.

47

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

- the shareholder-funded bill credit of $400 million to natural gas customers in 2016, as required by the Penalty Decision (see Note 9 of the Notes to the Condensed Consolidated Financial Statements);
- the timing and amounts of other fines or penalties that may be imposed in connection with the criminal prosecution of the Utility and the remaining investigations and other enforcement and litigation matters (see Note 9 of the Notes to the Condensed Consolidated Financial Statements);
- the timing and outcome of ratemaking proceedings, including the 2015 GT&S rate case and 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 decreased by $22 million during the three months ended March 31, 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 $6.5 billion in 2017.

Financing Activities

During the three months ended March 31, 2016, net cash provided by financing activities increased by $6 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 DOI has not yet set a timeline for the Utility’s response to the questions. 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 March 31, 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.

On February 27, 2016, a new shareholder derivative complaint, Bushkin v. Rambo et al., was filed in the United States District Court for the Northern District of California. This complaint 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 Bushkin complaint seeks to hold certain individual defendants responsible on claims of breach of fiduciary duty for damage to the company caused by the San Bruno accident, as well as by an alleged obstruction of the NTSB's investigation into the San Bruno accident and an alleged false statement related to PG&E Corporation’s corporate governance practices in its 2015 Proxy Statement. A case management conference on this matter is currently set for June 17, 2016.

A case management conference in the Iron Workers action pending in the United States District Court for the Northern District of California is currently set for June 3, 2016. Aside from the June 3, 2016 case management conference, the case has been stayed pending conclusion of the federal criminal proceedings against the Utility. As previously disclosed, 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.

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, representing a $124 million reduction from the previous request. The requested increase for 2018 was reduced from $489 million to $469 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.

On April 8, 2016, ORA submitted its testimony. For 2017, instead of the Utility’s requested increase, ORA recommended an $85 million reduction (approximately 1.1%) from the Utility’s currently authorized 2016 revenue requirement. For 2018 and 2019, ORA proposed increases of $274 million and $283 million, respectively (representing an approximately 3.5% annual increase), significantly below the Utility’s requested attrition increases of $469 million and $368 million, respectively. ORA also recommended to extend the GRC cycle another year and recommends a 2020 increase of $294 million (a 3.5% increase).

On April 29, 2016, TURN and several other intervening parties filed their testimonies. While TURN’s proposal does not include a revenue requirement recommendation for 2017, TURN recommended significant reductions to 2017 forecast operating expense, capital expenditures and other items. For 2018 and 2019, TURN presented a revenue requirement increase proposal of $469 million (representing an approximately 5.9% annual increase) and $250 million (representing an approximately 3.0% annual increase), respectively.

The table below summarizes the differences between the Utility’s revenue requirement increase proposal (based on the February 22, 2016 update), and ORA’s and TURN’s recommendations:

		ORA's Recommendation		TURN's Recommendation		
		(in millions)		(in millions)		
Year	Utility's Proposal (in millions)	Increase / (Decrease)	Difference (1)	(Decrease) Increase / (Decrease)	Difference	Increase/(Decrease)
2017	$333	$(85)	$(418)	$ N/A (2)	$N/A	
2018	469	274	(195)	469	-	
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.

50

For 2017, ORA accepted the Utility's capital expenditure forecasts in most lines of business. The reduction proposed by ORA is primarily related to operating expenses. ORA recommended reductions in programs across all major lines of business, including programs such as gas leak survey frequency, gas record consolidation, information technology programs, electric operations and automation, hydroelectric programs, residential rate reform education and outreach (ORA recommended that these costs be tracked in a memorandum account), and enterprise records and information management. ORA also recommended reductions in administrative and general expenses, employee incentive compensation and benefits, as well as general business expenses, such as insurance. ORA's recommended capital reductions for 2015, 2016, and 2017 would result in a rate base reduction of nearly $200 million in 2017 compared to the Utility's 2017 forecast of $24.5 billion in the GRC lines of business.

For 2017, TURN recommended significant reductions to forecast operating expense, capital expenditures and other items across the major lines of business. TURN recommended reductions in gas programs, including pipeline replacement, replacement of gas services; electric programs, including new business and substation equipment replacement and grid modernization programs; customer service programs; and real estate programs. TURN also recommended reductions in administrative and general expenses, as well as employee incentive compensation and benefits. For 2017, TURN's recommended reductions in operating expense and capital expenditures amount to approximately $166 million and $733 million, respectively.

The following table shows the difference between the Utility's requested increases in 2017 revenue requirements (based on the February 22, 2016 update) and ORA's recommended amounts by line of business:

(in millions) Line of Business:	Utility's Proposal			ORA's Recommendation Increase / (Decrease) (1)			Difference (1) (2) Increase / (Decrease)
Electric distribution	$71	1.7	%	$(146)	(3.5)	%	$(217)
Gas distribution	63	3.6		(59)	(3.4)		(122)
Electric generation	199	10.1		119	6.1		(80)
Total revenue requirements	$333	4.2	%	$(85)	(1.1)	%	$(418)

(1) Certain amounts have been rounded.

(2) Reflects the difference between the Utility's proposal and the recommendation.

TURN did not present revenue requirement recommendations by line of business.

In addition, 11 other parties provided recommendations. The Alliance for Nuclear Responsibility recommended for the Utility's Diablo Canyon nuclear power plant an annual filing on the Utility's plans to extend the license, a new performance-based ratemaking measure and various disallowances. The Coalition of California Utility Employees, which represents the International Brotherhood of Electrical Workers, recommended increasing funding for gas operations (such as for pipe replacement and leak survey frequency) and for electric operations (such as for fault location isolation and services restoration, also known as FLISR, overhead fuses, poles, and cable), and reducing depreciation expense for gas mains and poles. Other parties made various other recommendations regarding investments in connection with electric reliability, leak management practices, safety, executive compensation, customer outreach, local office closures, and supplier and employee diversity.

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	$4,284	$4,213	$71
Gas distribution	1,804	1,741	63
Electric generation	2,161	1,962	199
Total revenue requirements	$8,249	$7,916	$333
Cost Category: (in millions)			
Operations and maintenance	$1,833	$1,664	$169
Customer services	367	319	48
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	$8,249	$7,916	$333

According to the CPUC's procedural schedule, rebuttal testimonies are scheduled to be submitted by the Utility and other parties on May 27, 2016. Evidentiary hearings are to be held this summer, followed by a proposed decision to be released in November 2016 and a final CPUC decision to be issued in December 2016. 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.

2015 Gas Transmission and Storage Rate Case

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

ORA has recommended a 2015 revenue requirement of $1.044 billion, an increase of $329 million over authorized amounts. TURN recommended that the Utility not recover costs associated with hydrostatic testing for pipeline segments placed in service after January 1, 1956, as well as certain other work that TURN considers to be remedial. TURN also recommended the disallowance of about $200 million of capital expenditures incurred over the period 2011 through 2014 and recommended that about $500 million of capital expenditures during this period be subject to a reasonableness review and an independent audit. TURN stated that the Utility's cost recovery should not begin until the CPUC issues a decision on the independent audit.

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

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

The authorized revenue requirements in the 2015 GT&S rate case would be retroactive to January 1, 2015but would be recorded in the period a final decision is issued. Both decisions are anticipated in 2016.

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.

Asset Retirement Obligations

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCTP. On March 1, 2016, the Utility submitted its updated decommissioning cost estimate with the CPUC in its 2015 NDCTP. 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. 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 April 4, 2016, TURN and ORA submitted protests to the Utility's 2015 NDCTP. TURN indicated that it intends to thoroughly review the Utility's power plants cost estimate to determine overall reasonableness of the Utility's request and that the Utility should be required to provide an alternative assessment of decommissioning costs and funding requirements if the Diablo Canyon license is renewed.ORA requested an evidentiary hearing to develop a full and complete record of the support and justification for the Utility's 2015 NDCTP application. On April 14, 2016, the Utility filed its response and objected to TURN's proposal for an alternate assessment of Diablo Canyon costs.

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 $3.3 billion at March 31, 2016, which includes an $818 million adjustment to reflect the increased cost estimates described above, and $2.5 billion at December 31, 2015. These estimates are based on the 2016 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.

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 is expected to begin 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. In the re-opened proceeding, the CPUC will evaluate whether the incentive amounts awarded to the IOUs were just and reasonable, and whether any refunds are due.

On March 18, 2016, TURN and ORA submitted a joint proposal to require the refund of incentive awards that TURN and ORA argue were not calculated in accordance with the ratemaking mechanism rules and procedures the CPUC had previously adopted. TURN and ORA contended that the CPUC should order the Utility to refund $104 million, the entire incentive earnings award, plus interest, to customers as either (1) a revenue credit to customers' distribution and gas transportation accounts or (2) as a line item to the customers' first monthly bill following the issuance of a CPUC decision.

Additionally, on March 18, 2016, the IOUs submitted their proposals requesting that the CPUC reaffirm its prior decisions. The IOUs asserted that, given the many unresolved disputes about the data in the Energy Division's 2010 Evaluation Report, the CPUC appropriately used different data to calculate the awards. The IOUs noted that under the incentive ratemaking mechanism, any refunds of prior incentive earnings should be deducted from future incentive earnings claims.

On April 8, 2016, the IOUs, TURN and ORA filed comments on the proposals, in which the parties reiterated their requests. The Utility currently expects that evidentiary hearings, if ordered by the CPUC, would be held in July 2016. It is uncertain how the CPUC will resolve this matter and when the CPUC will issue a decision.

PG&E Corporation and the Utility believe it is reasonably possible that the Utility will be required to refund amounts previously awarded or incur other obligations related to this matter, but they are unable to reasonably estimate the amount of such refunds or other obligations. If the Utility were required to make a refund as TURN and ORA propose, PG&E Corporation's and the Utility's financial results would be affected by the amount of any refund-related charges.

OTHER MATTERS

Agreement with TransCanyon, LLC for Competitive Transmission Opportunities

On March 29, 2016, the Utilityentered into an agreement with TransCanyon, LLC, a joint venture between subsidiaries of Berkshire Hathaway Energy and Pinnacle West Capital Corporation, to jointly pursue competitive transmission opportunities solicited by the CAISO, the operator for the majority of the California electric transmission grid. The Utility and TransCanyon intend to jointly engage in the development of future transmission infrastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

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 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 distributed energy resources ("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 DERprovider(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. Comments on the proposal are due May 9, 2016 and reply comments are due May 23, 2016.

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 increased 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 customerslater in 2016. 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.

Electric Vehicle (EV) Infrastructure Development

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

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

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 under the CPUC's schedule, 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 three months ended March 31, 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.

57

CAUTIONARY LANGUAGE REGARDING FORWARD-LOOKING STATEMENTS

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

the timing and outcomes of 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 pending CPUC investigation of the Utility’s natural gas distribution record-keeping practices, 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 outcome 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, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and whether such matters negatively affect the final decisions to be issued in the 2015 GT&S rate case or other 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;

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;

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, including the California State Water Resources Board and the California State Lands Commission, that may affect the Utility's ability to continue operating Diablo Canyon; and whether the Utility decides to resume its pursuit to renew the two Diablo Canyon NRC operating licenses, and if so, whether the licenses are renewed;

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;

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 is able to protect its operating systems and networks from damage, disruption, or failure caused by cyber-attacks, computer viruses, or other hazards; whether the Utility's security measures are sufficient to protect against unauthorized or inadvertent disclosure of information contained in such systems and networks, 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 amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

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

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

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.

60

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 March 31,2016, 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 March 31,2016, 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. Although the trial previously had been scheduled to begin on April 26, 2016, the court vacated the trial date and no new trial date has been set. The court stated that it will set a new trial date in due course.

The maximum statutory fine for each felony count is $500,000, for total potential fines of $6.5 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 are 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 March 31, 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.

On February 27, 2016, a new shareholder derivative complaint, Bushkin v. Rambo et al., was filed in the United States District Court for the Northern District of California. This complaint 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 Bushkin complaint seeks to hold certain individual defendants responsible on claims of breach of fiduciary duty for damage to the company caused by the San Bruno accident, as well as by an alleged obstruction of the NTSB's investigation into the San Bruno accident and an alleged false statement related to PG&E Corporation’s corporate governance practices in its 2015 Proxy Statement. A case management conference on this matter is currently set for June 17, 2016.

A case management conference in the Iron Workers action pending in the United States District Court for the Northern District of California is currently set for June 3, 2016. Aside from the June 3, 2016 case management conference, the case has been stayed pending conclusion of the federal criminal proceedings against the Utility. As previously disclosed, 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.

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.

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.

Investigation of 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 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.

In connection with the Butte fire, approximately 32 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 1,300 individual plaintiffs and their insurance companies. In response to plaintiffs' and the Utility's requests, the California Judicial Council has authorized the coordination of all cases in the Superior Court of California, Sacramento County. 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 number of complaints may increase in the future. An initial case management conference was held on April 22, 2016 and the next case management conference is currently scheduled for May 24, 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.

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 1, Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations and in Note 9 of the Notes to the Condensed Consolidated Financial Statements. In addition, see "Part I, Item 3. Legal Proceedings" in the 2015 Form 10-K.

63

Diablo Canyon Nuclear Power Plant

For more information regarding the status of the 2003 settlement agreement between the Central Coast Regional Water Quality Control Board and the Utility, see "Part I, Item 3. Legal Proceedings" in the 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 is 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 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. The Utility has been in settlement discussions with the district attorney's office since that time. 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.

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

ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation's and the Utility's future financial condition, results of operations, and cash flows, see the section of the 2015 Form 10-K entitled "Risk Factors," as supplemented below, and the section of this quarterly report entitled "Cautionary Language Regarding Forward-Looking Statements."

PG&E Corporation 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.

In connection with the Butte fire, approximately 32 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 1,300 individual plaintiffs and their insurance companies. The number of complaints may increase in the future. PG&E Corporation's and the Utility's financial statements for the period ended March 31, 2016 reflect a provision of $350 million for property damages in connection with this matter. 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. 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. 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.

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

During the quarter ended March 31, 2016, PG&E Corporation made equity contributions totaling $65 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 March 31, 2016.

Issuer Purchases of Equity Securities

During the quarter ended March 31, 2016, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. During the quarter ended March 31, 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 three months ended March 31, 2016 was 0.75.The Utility's earnings to combined fixed charges and preferred stock dividends ratio for the three months ended March 31, 2016 was 0.74. 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 three months ended March 31, 2016 was 0.75. The statement of the foregoing ratio, together with the statement of the computation of the foregoing ratio filed as Exhibit 12.3 hereto, is included herein for the purpose of incorporating such information and Exhibit into PG&E Corporation's Registration Statement No. 333-193880.

ITEM 6. EXHIBITS

3	Bylaws of PG&E Corporation amended as of February 17, 2016
4	Twenty-Seventh Supplemental Indenture, dated as of March 1, 2016, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.95% Senior Notes due March 1, 2026 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed on March 1, 2016 (File No. 1-2348), Exhibit 4.1)
10.1	Term Loan Agreement, dated as of March 2, 2016, between Pacific Gas and Electric Company and The Bank of Tokyo-Mitsubishi UFJ, Ltd. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K filed on March 4, 2016 (File No. 1-2348), Exhibit 10.1)
*10.2	Restricted Stock Unit Agreement between Dinyar Mistry and PG&E Corporation dated February 23, 2016
*10.3	Separation agreement between Pacific Gas and Electric Company and Greg Kiraly dated February 18, 2016
*10.4	Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 16, 2016
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12.2	Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company
12.3	Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation
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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.

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/ DINYAR B. MISTRY
Dinyar B. Mistry

Senior Vice President, Human Resources, Chief Financial Officer and Controller

(duly authorized officer and principal financial officer)

Dated: May 4, 2016

EXHIBIT INDEX

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