PG&E Corp
Form 10-Q
May 03, 2018

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, 2018

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<br>77 Beale Street<br>P.O. Box 770000<br>San Francisco, California 94177 | Pacific Gas and Electric Company<br>77 Beale Street<br>P.O. Box 770000<br>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 the 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) has been subject to such filing requirements for the past 90 days.

| | |
|---|---|
| PG&E Corporation: | [X] Yes [ ] No |
| Pacific Gas and Electric Company: | [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, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer”, “accelerated filer”, “smaller reporting company”, and “emerging growth company” in Rule 12b-2 of the Exchange Act.

| | | |
|---|---|---|
| PG&E Corporation: | [X] Large accelerated filer | [ ] Accelerated filer |

| | | |
|---|---|---|
| | [ ] Non-accelerated filer (Do not check if a smaller reporting company) | |
| | [ ] Smaller reporting company | [ ] Emerging growth company |
| Pacific Gas and Electric Company: | [ ] Large accelerated filer | [ ] Accelerated filer |
| | [X] Non-accelerated filer (Do not check if a smaller reporting company) | |
| | [ ] Smaller reporting company | [ ] Emerging growth company |

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

| | |
|---|---|
| PG&E Corporation: | [ ] |
| Pacific Gas and Electric 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 24, 2018: | |
| PG&E Corporation: | 516,427,502 |
| Pacific Gas and Electric Company: | 264,374,809 |

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PG&E CORPORATION AND
PACIFIC GAS AND ELECTRIC COMPANY
FORM 10-Q
FOR THE QUARTERLY PERIOD ENDED MARCH 31, 2018

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GLOSSARY

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

| | |
|---|---|
| 2017 Form 10-K | PG&E Corporation and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2017 |
| ARO | asset retirement obligation |
| ASU | accounting standard update issued by the FASB (see below) |
| CAISO | California Independent System Operator |
| Cal Fire | California Department of Forestry and Fire Protection |
| CCA | Community Choice Aggregator |
| CEC | California Energy Resources Conservation and Development Commission |
| CEMA | Catastrophic Event Memorandum Account |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| DER | distributed energy resources |
| Diablo Canyon | Diablo Canyon nuclear power plant |
| DOGGR | the Division of Oil, Gas, and Geothermal Resources |
| DTSC | Department of Toxic Substances Control |
| EPS | earnings per common share |
| EV | electric vehicle |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| GAAP | U.S. Generally Accepted Accounting Principles |
| GHG | greenhouse gas |
| GRC | general rate case |
| GT&S | gas transmission and storage |
| HSM | hazardous substance memorandum account |
| IOU(s) | investor-owned utility(ies) |
| MD&A | Management’s Discussion and Analysis of Financial Condition and Results of Operations set forth in Item 2, of this Form 10-Q |
| MGP(s) | manufactured gas plants |
| NAV | net asset value |
| NDCTP | Nuclear Decommissioning Cost Triennial Proceedings |
| NEIL | Nuclear Electric Insurance Limited |
| NRC | Nuclear Regulatory Commission |
| OES | State of California Office of Emergency Services |
| OII | order instituting investigation |
| OIR | order instituting rulemaking |
| ORA | Office of Ratepayer Advocates |
| PCIA | Power Charge Indifference Adjustment |
| PFM | petition for modification |
| RAMP | Risk Assessment Mitigation Phase |
| ROE | return on equity |
| SEC | U.S. Securities and Exchange Commission |
| SED | Safety and Enforcement Division of the CPUC |
| Tax Act | Tax Cuts and Jobs Act of 2017 |
| TE | transportation electrification |

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| | |
|---|---|
| TO | transmission owner |
| TURN | The Utility Reform Network |
| Utility | Pacific Gas and Electric Company |
| VIE(s) | variable interest entity(ies) |
| WEMA | Wildfire Expense Memorandum Account |
| Westinghouse | Westinghouse Electric Company, LLC |

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) | 2018 | 2017 |
| Operating Revenues | | |
| Electric | $2,951 | $3,065 |
| Natural gas | 1,105 | 1,203 |
| Total operating revenues | 4,056 | 4,268 |
| Operating Expenses | | |
| Cost of electricity | 819 | 847 |
| Cost of natural gas | 289 | 325 |
| Operating and maintenance | 1,597 | 1,517 |
| Depreciation, amortization, and decommissioning | 752 | 712 |
| Total operating expenses | 3,457 | 3,401 |
| Operating Income | 599 | 867 |
| Interest income | 9 | 5 |
| Interest expense | (220) | (218) |
| Other income, net | 108 | 34 |
| Income Before Income Taxes | 496 | 688 |
| Income tax provision | 51 | 109 |
| Net Income | 445 | 579 |
| Preferred stock dividend requirement of subsidiary | 3 | 3 |
| Income Available for Common Shareholders | $442 | $576 |
| Weighted Average Common Shares Outstanding, Basic | 515 | 508 |
| Weighted Average Common Shares Outstanding, Diluted | 516 | 511 |
| Net Earnings Per Common Share, Basic | $0.86 | $1.13 |
| Net Earnings Per Common Share, Diluted | $0.86 | $1.13 |
| Dividends Declared Per Common Share | $— | $0.49 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | (Unaudited) Three Months Ended March 31, | |
|---|---|---|
| (in millions) | 2018 | 2017 |
| Net Income | $445 | $579 |
| Other Comprehensive Income | | |
| Pension and other post-retirement benefit plans obligations (net of taxes of $0 and $0, at respective dates) | — | — |
| Total other comprehensive income (loss) | — | — |
| Comprehensive Income | 445 | 579 |
| Preferred stock dividend requirement of subsidiary | 3 | 3 |
| Comprehensive Income Attributable to Common Shareholders | $442 | $576 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

| | (Unaudited) Balance At | |
|---|---|---|
| (in millions) | March 31, 2018 | December 31, 2017 |
| ASSETS | | |
| Current Assets | | |
| Cash and cash equivalents | $144 | $ 449 |
| Accounts receivable: | | |
| Customers (net of allowance for doubtful accounts of $59 and $64 at respective dates) | 1,222 | 1,243 |
| Accrued unbilled revenue | 851 | 946 |
| Regulatory balancing accounts | 1,367 | 1,222 |
| Other | 652 | 861 |
| Regulatory assets | 646 | 615 |
| Inventories: | | |
| Gas stored underground and fuel oil | 79 | 115 |
| Materials and supplies | 374 | 366 |
| Other | 520 | 464 |
| Total current assets | 5,855 | 6,281 |
| Property, Plant, and Equipment | | |
| Electric | 55,654 | 55,133 |
| Gas | 19,934 | 19,641 |
| Construction work in progress | 2,562 | 2,471 |
| Other | 2 | 3 |
| Total property, plant, and equipment | 78,152 | 77,248 |
| Accumulated depreciation | (23,811 ) | (23,459 ) |
| Net property, plant, and equipment | 54,341 | 53,789 |
| Other Noncurrent Assets | | |
| Regulatory assets | 3,724 | 3,793 |
| Nuclear decommissioning trusts | 2,842 | 2,863 |
| Income taxes receivable | 65 | 65 |
| Other | 1,327 | 1,221 |
| Total other noncurrent assets | 7,958 | 7,942 |
| TOTAL ASSETS | $68,154 | $ 68,012 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS

| | (Unaudited) | |
|---|---|---|
| | Balance At | |
| (in millions, except share amounts) | March 31, 2018 | December 31, 2017 |
| LIABILITIES AND EQUITY | | |
| Current Liabilities | | |
| Short-term borrowings | $967 | $ 931 |
| Long-term debt, classified as current | 394 | 445 |
| Accounts payable: | | |
| Trade creditors | 1,231 | 1,646 |
| Regulatory balancing accounts | 1,264 | 1,120 |
| Other | 710 | 517 |
| Disputed claims and customer refunds | 245 | 243 |
| Interest payable | 145 | 217 |
| Other | 1,964 | 2,010 |
| Total current liabilities | 6,920 | 7,129 |
| Noncurrent Liabilities | | |
| Long-term debt | 17,407 | 17,753 |
| Regulatory liabilities | 8,586 | 8,679 |
| Pension and other post-retirement benefits | 2,094 | 2,128 |
| Asset retirement obligations | 4,946 | 4,899 |
| Deferred income taxes | 5,990 | 5,822 |
| Other | 2,228 | 2,130 |
| Total noncurrent liabilities | 41,251 | 41,411 |
| Commitments and Contingencies (Note 9) | | |
| Equity | | |
| Shareholders' Equity | | |
| Common stock, no par value, authorized 800,000,000 shares; 516,003,957 and 514,755,845 shares outstanding at respective dates | 12,701 | 12,632 |
| Reinvested earnings | 7,043 | 6,596 |
| Accumulated other comprehensive loss | (13 ) | (8 ) |
| Total shareholders' equity | 19,731 | 19,220 |
| Noncontrolling Interest - Preferred Stock of Subsidiary | 252 | 252 |
| Total equity | 19,983 | 19,472 |
| TOTAL LIABILITIES AND EQUITY | $68,154 | $ 68,012 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

PG&E CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

| | (Unaudited) Three Months Ended March 31, | |
|---|---|---|
| (in millions) | 2018 | 2017 |
| Cash Flows from Operating Activities | | |
| Net income | $445 | $579 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, amortization, and decommissioning | 752 | 712 |
| Allowance for equity funds used during construction | (32) | (19) |
| Deferred income taxes and tax credits, net | 178 | 252 |
| Other | 30 | 8 |
| Effect of changes in operating assets and liabilities: | | |
| Accounts receivable | 120 | 373 |
| Butte-related insurance receivable | 197 | (7) |
| Inventories | 28 | (2) |
| Accounts payable | 24 | (13) |
| Butte-related third-party claims | (118) | (44) |
| Other current assets and liabilities | (145) | (137) |
| Regulatory assets, liabilities, and balancing accounts, net | 114 | (176) |
| Other noncurrent assets and liabilities | (81) | 48 |
| Net cash provided by operating activities | 1,512 | 1,574 |
| Cash Flows from Investing Activities | | |
| Capital expenditures | (1,470) | (1,216) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 494 | 470 |
| Purchases of nuclear decommissioning trust investments | (505) | (493) |
| Other | 6 | 4 |
| Net cash used in investing activities | (1,475) | (1,235) |
| Cash Flows from Financing Activities | | |
| Net issuances (repayments) of commercial paper, net of discount of $0 and $2 at respective dates | 36 | (755) |
| Short-term debt financing | 250 | 250 |
| Short-term debt matured | (250) | (250) |
| Proceeds from issuance of long-term debt, net of discount and issuance costs of $0 and $10 at respective dates | — | 590 |
| Long-term debt matured or repurchased | (400) | — |
| Common stock issued | 35 | 146 |
| Common stock dividends paid | — | (243) |
| Other | (13) | (90) |
| Net cash used in financing activities | (342) | (352) |
| Net change in cash and cash equivalents | (305) | (13) |
| Cash and cash equivalents at January 1 | 449 | 177 |
| Cash and cash equivalents at March 31 | $144 | $164 |

| | | |
|---|---|---|
| Supplemental disclosures of cash flow information | | |
| Cash received (paid) for: | | |
| Interest, net of amounts capitalized | $(268) | $(246) |
| Income taxes, net | — | 1 |
| Supplemental disclosures of noncash investing and financing activities | | |
| Common stock dividends declared but not yet paid | $— | $250 |
| Capital expenditures financed through accounts payable | 255 | 237 |
| Noncash common stock issuances | — | 4 |
| Terminated capital leases | 137 | — |

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) | 2018 | 2017 |
| Operating Revenues | | |
| Electric | $2,951 | $3,067 |
| Natural gas | 1,105 | 1,204 |
| Total operating revenues | 4,056 | 4,271 |
| Operating Expenses | | |
| Cost of electricity | 819 | 847 |
| Cost of natural gas | 289 | 325 |
| Operating and maintenance | 1,597 | 1,518 |
| Depreciation, amortization, and decommissioning | 752 | 712 |
| Total operating expenses | 3,457 | 3,402 |
| Operating Income | 599 | 869 |
| Interest income | 9 | 5 |
| Interest expense | (217) | (216) |
| Other income, net | 109 | 31 |
| Income Before Income Taxes | 500 | 689 |
| Income tax provision | 48 | 120 |
| Net Income | 452 | 569 |
| Preferred stock dividend requirement | 3 | 3 |
| Income Available for Common Stock | $449 | $566 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | (Unaudited) Three Months Ended March 31, | |
|---|---|---|
| (in millions) | 2018 | 2017 |
| Net Income | $452 | $569 |
| Other Comprehensive Income | | |
| Pension and other post-retirement benefit plans obligations (net of taxes of $0 and $0, at respective dates ) | — | 1 |
| Total other comprehensive income (loss) | — | 1 |
| Comprehensive Income | $452 | $570 |

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, 2018 | December 31, 2017 |
| ASSETS | | |
| Current Assets | | |
| Cash and cash equivalents | $122 | $447 |
| Accounts receivable: | | |
| Customers (net of allowance for doubtful accounts of $59 and $64 at respective dates) | 1,222 | 1,243 |
| Accrued unbilled revenue | 851 | 946 |
| Regulatory balancing accounts | 1,367 | 1,222 |
| Other | 661 | 862 |
| Regulatory assets | 646 | 615 |
| Inventories: | | |
| Gas stored underground and fuel oil | 79 | 115 |
| Materials and supplies | 374 | 366 |
| Other | 519 | 465 |
| Total current assets | 5,841 | 6,281 |
| Property, Plant, and Equipment | | |
| Electric | 55,654 | 55,133 |
| Gas | 19,934 | 19,641 |
| Construction work in progress | 2,562 | 2,471 |
| Total property, plant, and equipment | 78,150 | 77,245 |
| Accumulated depreciation | (23,808 ) | (23,456 ) |
| Net property, plant, and equipment | 54,342 | 53,789 |
| Other Noncurrent Assets | | |
| Regulatory assets | 3,724 | 3,793 |
| Nuclear decommissioning trusts | 2,842 | 2,863 |
| Income taxes receivable | 64 | 64 |
| Other | 1,200 | 1,094 |
| Total other noncurrent assets | 7,830 | 7,814 |
| TOTAL ASSETS | $68,013 | $67,884 |

See accompanying Notes to the Condensed Consolidated Financial Statements.

PACIFIC GAS AND ELECTRIC COMPANY
CONDENSED CONSOLIDATED BALANCE SHEETS

| (in millions. except share amounts) | (Unaudited) Balance At March 31, 2018 | December 31, 2017 |
|---|---|---|
| LIABILITIES AND EQUITY | | |
| Current Liabilities | | |
| Short-term borrowings | $846 | $ 799 |
| Long-term debt, classified as current | 45 | 445 |
| Accounts payable: | | |
| Trade creditors | 1,231 | 1,644 |
| Regulatory balancing accounts | 1,264 | 1,120 |
| Other | 760 | 538 |
| Disputed claims and customer refunds | 245 | 243 |
| Interest payable | 145 | 214 |
| Other | 1,982 | 2,018 |
| Total current liabilities | 6,518 | 7,021 |
| Noncurrent Liabilities | | |
| Long-term debt | 17,407 | 17,403 |
| Regulatory liabilities | 8,586 | 8,679 |
| Pension and other post-retirement benefits | 1,990 | 2,026 |
| Asset retirement obligations | 4,946 | 4,899 |
| Deferred income taxes | 6,130 | 5,963 |
| Other | 2,240 | 2,146 |
| Total noncurrent liabilities | 41,299 | 41,116 |
| 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 | 8,505 | 8,505 |
| Reinvested earnings | 10,107 | 9,656 |
| Accumulated other comprehensive income | 4 | 6 |
| Total shareholders' equity | 20,196 | 19,747 |
| TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY | $68,013 | $ 67,884 |

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) | 2018 | 2017 |
| Cash Flows from Operating Activities | | |
| Net income | $452 | $569 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | |
| Depreciation, amortization, and decommissioning | 752 | 712 |
| Allowance for equity funds used during construction | (32) | (19) |
| Deferred income taxes and tax credits, net | 175 | 264 |
| Other | (1) | 57 |
| Effect of changes in operating assets and liabilities: | | |
| Accounts receivable | 112 | 322 |
| Butte-related insurance receivable | 197 | (7) |
| Inventories | 28 | (2) |
| Accounts payable | 55 | (3) |
| Butte-related third-party claims | (118) | (44) |
| Other current assets and liabilities | (131) | (113) |
| Regulatory assets, liabilities, and balancing accounts, net | 114 | (176) |
| Other noncurrent assets and liabilities | (87) | 38 |
| Net cash provided by operating activities | 1,516 | 1,598 |
| Cash Flows from Investing Activities | | |
| Capital expenditures | (1,470) | (1,216) |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 494 | 470 |
| Purchases of nuclear decommissioning trust investments | (505) | (493) |
| Other | 6 | 4 |
| Net cash used in investing activities | (1,475) | (1,235) |
| Cash Flows from Financing Activities | | |
| Net issuances (repayments) of commercial paper, net of discount of $0 and $2 at respective dates | 47 | (755) |
| Short-term debt financing | 250 | 250 |
| Short-term debt matured | (250) | (250) |
| Proceeds from issuance of long-term debt, net of discount and issuance costs of $0 and $10 at respective dates | — | 590 |
| Long-term debt matured or repurchased | (400) | — |
| Preferred stock dividends paid | — | (3) |
| Common stock dividends paid | — | (244) |
| Equity contribution from PG&E Corporation | — | 125 |
| Other | (13) | (87) |
| Net cash used in financing activities | (366) | (374) |
| Net change in cash and cash equivalents | (325) | (11) |
| Cash and cash equivalents at January 1 | 447 | 71 |
| Cash and cash equivalents at March 31 | $122 | $60 |

| | | |
|---|---|---|
| Supplemental disclosures of cash flow information | | |
| Cash received (paid) for: | | |
| Interest, net of amounts capitalized | $(259) | $(242) |
| Supplemental disclosures of noncash investing and financing activities | | |
| Capital expenditures financed through accounts payable | $255 | $237 |
| Terminated capital leases | 137 | — |

See accompanying Notes to the Condensed Consolidated Financial Statements.

NOTES TO THE CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)

## NOTE 1: ORGANIZATION AND BASIS OF PRESENTATION

PG&E Corporation is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility serving 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 assess financial performance and allocate resources on a consolidated basis (i.e., the companies operate in one segment).

The accompanying Condensed Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the interim period reporting requirements of Form 10-Q and reflect all adjustments (consisting only of normal recurring adjustments) that management believes are necessary for the fair presentation of PG&E Corporation’s and the Utility’s financial condition, results of operations, and cash flows for the periods presented.  The information at December 31, 2017 in the Condensed Consolidated Balance Sheets included in this quarterly report was derived from the audited Consolidated Balance Sheets in Item 8 of the 2017 Form 10-K.  This quarterly report should be read in conjunction with the 2017 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, insurance recoveries, environmental remediation liabilities, AROs, and pension and other post-retirement benefit plans obligations.  Management believes that its estimates and assumptions reflected in the Condensed Consolidated Financial Statements are appropriate and reasonable.  A change in management’s estimates or assumptions could result in an adjustment that would 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.

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City (the “Northern California wildfires”).  According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in Northern California that, in total, burned over 245,000 acres and destroyed an estimated 8,900 structures. The wildfires also resulted in 44 fatalities. The Northern California wildfires are under investigation by Cal Fire and the CPUC, including the possible role of the Utility’s power lines and other facilities. The Utility expects that Cal Fire will issue a report or reports stating its conclusions as to the sources of ignition of the fires and the ways that they progressed. Further, the CPUC's SED is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire-impacted areas. See "Northern California Wildfires" in Note 9 below.

## NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

For a summary of the significant accounting policies used by PG&E Corporation and the Utility, see Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 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 has a controlling interest or was the primary beneficiary of any of these VIEs at March 31, 2018, the Utility 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, 2018, it did not consolidate any of them.

Pension and Other Post-Retirement 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, 2018 and 2017 were as follows:

| | Pension Benefits | | Other Benefits | |
|---|---|---|---|---|
| | Three Months Ended March 31, | | | |
| (in millions) | 2018 | 2017 | 2018 | 2017 |
| Service cost for benefits earned | $128 | $118 | $16 | $15 |
| Interest cost | 172 | 179 | 17 | 19 |
| Expected return on plan assets | (255) | (193) | (33) | (24) |
| Amortization of prior service cost | (1) | (2) | 4 | 4 |
| Amortization of net actuarial loss | 1 | 6 | (1) | 1 |
| Net periodic benefit cost | 45 | 108 | 3 | 15 |
| Regulatory account transfer [1] | 39 | (23) | — | — |
| Total | $84 | $85 | $3 | $15 |

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

Non-service costs are reflected in Other income, net on the Condensed Consolidated Statements of Income.

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

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

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

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| | Three Months Ended March 31, 2018 | | |
| Beginning balance | $(25) | $ 17 | $(8 ) |
| Amounts reclassified from other comprehensive income: | | | |
| Amortization of prior service cost (net of taxes of $0 and $1, respectively) [1] | (1 ) | 3 | 2 |
| Amortization of net actuarial loss (net of taxes of $0 and $0, respectively) [1] | 1 | (1 ) | — |
| Regulatory account transfer (net of taxes of $0 and $1, respectively) [1] | — | (2 ) | (2 ) |
| Reclassification of stranded income tax to retained earnings (net of taxes of $0 and $0, respectively) | (5 ) | — | (5 ) |
| Net current period other comprehensive gain (loss) | (5 ) | — | (5 ) |
| Ending balance | $(30) | $ 17 | $(13) |

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

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| | Three Months Ended March 31, 2017 | | |
| Beginning balance | $(25) | $ 16 | $(9 ) |
| Amounts reclassified from other comprehensive income: [1] | | | |
| Amortization of prior service cost (net of taxes of $1 and $2, respectively) | (1 ) | 2 | 1 |
| Amortization of net actuarial loss (net of taxes of $3, and $0, respectively) | 3 | 1 | 4 |
| Regulatory account transfer (net of taxes of $2 and $2, respectively) | (2 ) | (3 ) | (5 ) |
| Net current period other comprehensive gain (loss) | — | — | — |
| Ending balance | $(25) | $ 16 | $(9 ) |

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

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

Recently Adopted Accounting Standards

Revenue Recognition Standard

In May 2014, the FASB issued ASU No. 2014-9, Revenue from Contracts with Customers (Topic 606), which amends the previous revenue recognition guidance. The objective of the new standard is to provide a single, comprehensive revenue recognition model for all contracts with customers to improve comparability across entities, industries, jurisdictions, and capital markets and to provide more useful information to users of financial statements through improved and expanded disclosure requirements. PG&E Corporation and the Utility applied the requirements using the modified retrospective method when the ASU became effective on January 1, 2018. The adoption of this guidance did not have a material impact on the Condensed Consolidated Financial Statements as of the adoption date or for the three months ended March 31, 2018. A majority of the Utility's revenue from contracts with customers continues to be recognized on a monthly basis based on applicable tariffs and customers' monthly consumption. Such revenue is recognized using the invoice practical expedient which allows an entity to recognize revenue in the amount that directly corresponds to the value transferred to the customer.

Revenue from Contracts with Customers

The Utility recognizes revenues when electricity and natural gas services are delivered. The Utility records unbilled revenues for the estimated amount of energy delivered to customers but not yet billed at the end of the period. Unbilled revenues are included in accounts receivable on the Condensed Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements. Revenues can vary significantly from period to period as a result of seasonality, weather, and customer usage patterns.

The FERC authorizes the Utility's revenue requirements in periodic (often annual) TO rate cases. The Utility's ability to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled, net of revenues subject to refund.

Regulatory Balancing Account Revenue

The CPUC authorizes most of the Utility's revenues in the Utility's GRC and its GT&S rate cases, which generally occur every three or four years. The Utility's ability to recover revenue requirements authorized by the CPUC in these rate cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The Utility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, electric and natural gas operating revenue is recognized ratably over the year. The Utility records a balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas, and to fund public purpose, demand response, and customer energy efficiency programs. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred. The Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. As a result, these differences have no impact on net income.

The following table presents the Utility's revenues disaggregated by type of customer:

| (in millions) | Three Months Ended March 31, 2018 |
|---|---|
| Electric | |
| Revenue from contracts with customers | |
| Residential | $1,336 |
| Commercial | 1,073 |
| Industrial | 324 |
| Agricultural | 125 |
| Public street and highway lighting | 20 |
| Other [1] | (201 ) |
| Total revenue from contracts with customers - electric | 2,677 |
| Regulatory balancing accounts [2] | 274 |
| Total electric operating revenue | $2,951 |
| | |
| Natural gas | |
| Revenue from contracts with customers | |
| Residential | $958 |
| Commercial | 196 |
| Transportation service only | 297 |
| Other [1] | (52 ) |
| Total revenue from contracts with customers - gas | 1,399 |
| Regulatory balancing accounts [2] | (294 ) |
| Total natural gas operating revenue | 1,105 |
| Total operating revenues | $4,056 |

[1] This activity is primarily related to the change in unbilled revenue, partially offset by other miscellaneous revenue items.
[2] These amounts represent revenues authorized to be billed or refunded to customers.

Presentation of Net Periodic Pension and Post-Retirement Benefit Costs

In March 2017, the FASB issued ASU 2017-07, Compensation – Retirement Benefits (Topic 715), which amends the guidance relating to the presentation of net periodic pension cost and net periodic other post-retirement benefit costs. PG&E Corporation and the Utility applied the requirements when the ASU became effective on January 1, 2018.

On a retrospective basis, the amendment requires an employer to separate the service cost component from the other components of net benefit cost and provides explicit guidance on how to present the service cost component and other components in the income statement. As a result, the Condensed Consolidated Statements of Income for PG&E Corporation and the Utility were restated. This change resulted in increases to Operating and maintenance expenses and Other income, net, of $13 million and $14 million for PG&E Corporation and the Utility, respectively, for the three months ended March 31, 2017.

On a prospective basis, the ASU limits the component of net benefit cost eligible to be capitalized to service costs. The FERC has allowed and the Utility has made a one-time election to adopt the new FASB guidance for regulatory filing purposes. In January 2018, the CPUC approved modifications to the Utility's calculation for pension-related revenue requirements to allow for capitalization of only the service cost component determined by a plan's actuaries. The capitalization of service costs only will result in higher rate base and will lead to a reduction in the Utility's 2018 revenues. The changes in capitalization of retirement benefits did not have a material impact on PG&E Corporation's and the Utility's Condensed Consolidated Financial Statements.

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 guidance relating to the recognition, measurement, presentation, and disclosure of financial instruments. The amendments require equity investments (excluding those accounted for under the equity method or those that result in consolidation) to be measured at fair value, with changes in fair value recognized in net income. The majority of PG&E Corporation's and the Utility's investments are held in the nuclear decommissioning trusts and gains or losses are refundable or recoverable, respectively, from customers through rates. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018 and did not have a material impact on the Condensed Consolidated Financial Statements and related disclosures.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income

In February 2018, the FASB issued ASU No. 2018-02, Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. The amendments in this update allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Act. When amounts are reclassified from accumulated other comprehensive income to the Condensed Consolidated Statement of Income, PG&E Corporation and the Utility recognize the related income tax expense at the tax rate in effect at that time. The ASU is effective for PG&E Corporation and the Utility on January 1, 2019, and early adoption is permitted. PG&E Corporation and the Utility early adopted this ASU on January 1, 2018, resulting in an immaterial reclassification.

Accounting Standards Issued But Not Yet Adopted

Recognition of Lease Assets and Liabilities

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842), which amends the guidance relating to the definition of a lease, recognition of lease assets and lease liabilities on the balance sheet, and the disclosure of key information about leasing arrangements. In November, 2017, the FASB tentatively decided to amend the new leasing guidance such that entities may elect not to restate their comparative periods in the period of adoption. Under the new standard, all lessees must recognize an asset and liability on the balance sheet. Operating leases were previously not recognized on the balance sheet. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019, with early adoption permitted. PG&E Corporation and the Utility plan to adopt this guidance in the first quarter of 2019. PG&E Corporation and the Utility expect this standard to increase lease assets and lease liabilities on the Condensed Consolidated Balance Sheets and do not expect the guidance will have a material impact on the Condensed Consolidated Statements of Income, Statements of Cash Flows and related disclosures.

NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

Regulatory Assets and Liabilities

Current Regulatory Assets

At March 31, 2018 and December 31, 2017, the Utility had current regulatory assets of $646 million and $615 million, which included $444 million and $426 million, respectively, of costs related to CEMA fire prevention and vegetation management.

Long-Term Regulatory Assets

Long-term regulatory assets are comprised of the following:

| (in millions) | Asset Balance at March 31, 2018 | December 31, 2017 |
|---|---|---|
| Pension benefits | $1,915 | $ 1,954 |
| Environmental compliance costs | 749 | 837 |
| Utility retained generation | 308 | 319 |
| Price risk management | 68 | 65 |
| Unamortized loss, net of gain, on reacquired debt | 88 | 79 |
| Catastrophic event memorandum account | 314 | 274 |
| Other | 282 | 265 |
| Total long-term regulatory assets | $3,724 | $ 3,793 |

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

| (in millions) | Liability Balance at March 31, 2018 | December 31, 2017 |
|---|---|---|
| Cost of removal obligations | $5,674 | $ 5,547 |
| Deferred income taxes | 873 | 1,021 |
| Recoveries in excess of AROs | 533 | 624 |
| Public purpose programs | 591 | 590 |
| Other | 915 | 897 |
| Total long-term regulatory liabilities | $8,586 | $ 8,679 |

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

Regulatory Balancing Accounts

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

| (in millions) | Receivable Balance at March 31, 2018 | December 31, 2017 |
|---|---|---|
| Electric distribution | $176 | $ — |
| Electric transmission | 125 | 139 |
| Utility generation | 203 | — |
| Gas distribution and transmission | 269 | 486 |
| Energy procurement | 1 | 71 |
| Public purpose programs | 115 | 103 |
| Other | 478 | 423 |
| Total regulatory balancing accounts receivable | $1,367 | $ 1,222 |

| (in millions) | Payable Balance at March 31, 2018 | December 31, 2017 |
|---|---|---|
| Electric distribution | $— | $ 72 |
| Electric transmission | 108 | 120 |
| Utility generation | — | 14 |
| Energy procurement | 265 | 149 |
| Public purpose programs | 491 | 452 |
| Other | 400 | 313 |
| Total regulatory balancing accounts payable | $1,264 | $ 1,120 |

For more information, see Note 3 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

## 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, 2018:

| (in millions) | Termination Date | Facility Limit | Letters of Credit Outstanding | Commercial Paper | Facility Availability |
|---|---|---|---|---|---|
| PG&E Corporation | April 2022 | $300 [1] | $ — | $ 121 | $ 179 |
| Utility | April 2022 | 3,000 [2] | 48 | 97 | 2,855 |
| Total revolving credit facilities | | $3,300 | $ 48 | $ 218 | $ 3,034 |

[1] Includes a $50 million lender commitment to the letter of credit sublimit and a $100 million commitment for swingline loans defined as loans that are made available on a same-day basis and are repayable in full within 7 days.
[2] Includes a $500 million lender commitment to the letter of credit sublimit and a $75 million commitment for swingline loans.

Other Short-term Borrowings

In February 2018, the Utility’s $250 million floating rate unsecured term loan, issued in February 2017, matured and was repaid. Additionally, in February 2018, the Utility entered into a $250 million floating rate unsecured term loan that will mature on February 22, 2019. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility’s outstanding commercial paper.

Long-term Debt Issuances and Redemptions

In January 2018, the Utility sent a notice of redemption to redeem all $400 million aggregate principal amount of the 8.25% Senior Notes due October 15, 2018. On January 31, 2018, the Utility deposited with the trustee funds sufficient to effect the early redemption of these bonds and satisfy and discharge its remaining obligation of $400 million on February 18, 2018.

In April 2018, PG&E Corporation entered into a $350 million floating rate unsecured term loan. The term loan matures on April 16, 2020, unless extended by PG&E Corporation pursuant to the terms of the term loan agreement. The proceeds were used for general corporate purposes, including the early redemption of PG&E Corporation's outstanding $350 million principal amount of 2.40% Senior Notes due March 1, 2019. On April 16, 2018, PG&E Corporation issued a notice of early redemption of these bonds, with a redemption date of April 26, 2018.

Variable Rate Interest

At March 31, 2018, 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 1.52% to 1.65%.  At March 31, 2018, the interest rates on the $149 million principal amount of pollution control bonds Series 2009 A and B, and the related loan agreements, were 1.60%.

NOTE 5: EQUITY

PG&E Corporation’s and the Utility’s changes in equity for the three months ended March 31, 2018 were as follows:

| | PG&E Corporation | Utility |
|---|---|---|
| (in millions) | Total Equity | Total Shareholders' Equity |
| Balance at December 31, 2017 | $ 19,472 | $ 19,747 |
| Comprehensive income | 445 | 452 |
| Common stock issued | 35 | — |
| Share-based compensation | 34 | — |
| Preferred stock dividend requirement | — | (3) |
| Preferred stock dividend requirement of subsidiary | (3) | — |
| Balance at March 31, 2018 | $ 19,983 | $ 20,196 |

There were no issuances under the PG&E Corporation February 2017 equity distribution agreement for the three months ended March 31, 2018.  As of March 31, 2018, the remaining gross sales available under this agreement were $246.3 million.

PG&E Corporation issued common stock under the PG&E Corporation 401(k) plan and share-based compensation plans.  During the three months ended March 31, 2018, 1.2 million shares were issued for cash proceeds of $35.1 million under these plans.

NOTE 6: EARNINGS PER SHARE

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

| | Three Months Ended March 31, | |
|---|---|---|
| (in millions, except per share amounts) | 2018 | 2017 |
| Income available for common shareholders | $442 | $576 |
| Weighted average common shares outstanding, basic | 515 | 508 |
| Add incremental shares from assumed conversions: | | |
| Employee share-based compensation | 1 | 3 |
| Weighted average common shares outstanding, diluted | 516 | 511 |
| Total earnings per common share, diluted | $0.86 | $1.13 |

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

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Condensed Consolidated Balance Sheets. These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives under the applicable ratemaking mechanism in place as long as 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:

| Underlying Product | Instruments | Contract Volume at March 31, 2018 | Contract Volume at December 31, 2017 |
|---|---|---|---|
| Natural Gas [1] (MMBtus [2]) | Forwards, Futures and Swaps | 184,948,051 | 228,768,745 |
| | Options | 31,481,247 | 60,736,806 |
| Electricity (Megawatt-hours) | Forwards, Futures and Swaps | 2,602,376 | 2,872,013 |
| | Congestion Revenue Rights [3] | 304,484,831 | 312,272,177 |

[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, 2018, 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 | $30 | $ (2 ) | $ 6 | $ 34 |
| Other noncurrent assets – other | 98 | (1 ) | — | 97 |
| Current liabilities – other | (52 ) | 2 | 19 | (31 ) |
| Noncurrent liabilities – other | (68 ) | 1 | 12 | (55 ) |
| Total commodity risk | $8 | $ — | $ 37 | $ 45 |

At December 31, 2017, 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 | $30 | $ (3 ) | $ 10 | $ 37 |
| Other noncurrent assets – other | 103 | (1 ) | — | 102 |
| Current liabilities – other | (47 ) | 3 | 13 | (31 ) |
| Noncurrent liabilities – other | (66 ) | 1 | 8 | (57 ) |
| Total commodity risk | $20 | $ — | $ 31 | $ 51 |

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

| | Commodity Risk Three Months Ended March 31, | |
|---|---|---|
| (in millions) | 2018 | 2017 |

| | | |
|---|---|---|
| Unrealized gain (loss) - regulatory assets and liabilities [1] | $(12) | $(48) |
| Realized loss - cost of electricity [2] | (18 ) | (5 ) |
| Realized loss - cost of natural gas [2] | (1 ) | (1 ) |
| Net commodity risk | $(31) | $(54) |

[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, 2018, 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:

| (in millions) | Balance at March 31, 2018 | December 31, 2017 |
|---|---|---|
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $(1) | $ (1) |
| Related derivatives in an asset position | — | — |
| Collateral posting in the normal course of business related to these derivatives | — | — |
| Net position of derivative contracts/additional collateral posting requirements [1] | $(1) | $ (1) |

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

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

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

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

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

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below.

Assets held in rabbi trusts are held by PG&E Corporation and not the Utility.

| | Fair Value Measurements March 31, 2018 | | | | |
|---|---|---|---|---|---|
| (in millions) | Level 1 | Level 2 | Level 3 | Netting [1] | Total |
| Assets: | | | | | |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | $28 | — | — | — | $28 |
| Global equity securities | 1,862 | — | — | — | 1,862 |
| Fixed-income securities | 776 | 599 | — | — | 1,375 |
| Assets measured at NAV | — | — | — | — | 17 |
| Total nuclear decommissioning trusts [2] | 2,666 | 599 | — | — | 3,282 |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | — | 2 | 125 | 3 | 130 |
| Gas | — | 1 | — | — | 1 |
| Total price risk management instruments | — | 3 | 125 | 3 | 131 |
| Rabbi trusts | | | | | |
| Fixed-income securities | — | 74 | — | — | 74 |
| Life insurance contracts | — | 69 | — | — | 69 |
| Total rabbi trusts | — | 143 | — | — | 143 |
| Long-term disability trust | | | | | |
| Short-term investments | 5 | — | — | — | 5 |
| Assets measured at NAV | — | — | — | — | 162 |
| Total long-term disability trust | 5 | — | — | — | 167 |
| TOTAL ASSETS | $2,671 | $745 | $125 | $ 3 | $3,723 |
| Liabilities: | | | | | |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | $8 | $25 | $85 | $ (33 ) | $85 |
| Gas | — | 2 | — | (1 ) | 1 |
| TOTAL LIABILITIES | $8 | $27 | $85 | $ (34 ) | $86 |

[1] Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
[2] Represents amount before deducting $440 million, primarily related to deferred taxes on appreciation of investment value.

| (in millions) | Fair Value Measurements December 31, 2017 Level 1 | Level 2 | Level 3 | Netting [1] | Total |
|---|---|---|---|---|---|
| Assets: | | | | | |
| Short-term investments | $385 | $— | $— | $— | $385 |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 23 | — | — | — | 23 |
| Global equity securities | 1,967 | — | — | — | 1,967 |
| Fixed-income securities | 733 | 562 | — | — | 1,295 |
| Assets measured at NAV | — | — | — | — | 18 |
| Total nuclear decommissioning trusts [2] | 2,723 | 562 | — | — | 3,303 |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | — | 3 | 129 | 6 | 138 |
| Gas | — | 1 | — | — | 1 |
| Total price risk management instruments | — | 4 | 129 | 6 | 139 |
| Rabbi trusts | | | | | |
| Fixed-income securities | — | 72 | — | — | 72 |
| Life insurance contracts | — | 71 | — | — | 71 |
| Total rabbi trusts | — | 143 | — | — | 143 |
| Long-term disability trust | | | | | |
| Short-term investments | 8 | — | — | — | 8 |
| Assets measured at NAV | — | — | — | — | 167 |
| Total long-term disability trust | 8 | — | — | — | 175 |
| TOTAL ASSETS | $3,116 | $709 | $129 | $6 | $4,145 |
| Liabilities: | | | | | |
| Price risk management instruments (Note 7) | | | | | |
| Electricity | $10 | $15 | $87 | $(25) | $87 |
| Gas | — | 1 | — | — | 1 |
| TOTAL LIABILITIES | $10 | $16 | $87 | $(25) | $88 |

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $440 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, 2018 and 2017.

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 fixed-income 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

Investments in the nuclear decommissioning trusts and the long-term disability trust that are measured at fair value using the NAV per share practical expedient have not been classified in the fair value hierarchy tables above. The fair value amounts are included in the tables above in order to reconcile to the amounts presented in the Condensed Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities and asset-backed securities.

Price Risk Management Instruments

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

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

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

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

Level 3 Measurements and Sensitivity Analysis

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

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

| (in millions) | Fair Value at March 31, 2018 | | | | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Valuation Technique | Unobservable Input | Range [1] |
| Congestion revenue rights | $125 | $ 25 | Market approach | CRR auction prices | $ (7.44) - 13.91 |
| Power purchase agreements | $— | $ 60 | Discounted cash flow | Forward prices | $ 18.81 - 38.80 |

[1] Represents price per megawatt-hour

| (in millions) | Fair Value at December 31, 2017 | | | | |
|---|---|---|---|---|---|
| Fair Value Measurement | Assets | Liabilities | Valuation Technique | Unobservable Input | Range [1] |
| Congestion revenue rights | $ 129 | $ 24 | Market approach | CRR auction prices | $ (16.03) - 11.99 |
| Power purchase agreements | $ — | $ 63 | Discounted cash flow | Forward prices | $ 18.81 - 38.80 |

[1] Represents price per megawatt-hour

Level 3 Reconciliation

The following table presents the reconciliation for Level 3 price risk management instruments for the three months ended March 31, 2018 and 2017:

| (in millions) | Price Risk Management Instruments 2018 | 2017 |
|---|---|---|
| Asset (liability) balance as of January 1 | $ 42 | $ 55 |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [1] | (2 ) | (6 ) |
| Asset (liability) balance as of March 31 | $ 40 | $ 49 |

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

Financial Instruments

PG&E Corporation and the Utility use the following methods and assumptions in estimating fair value for financial instruments: the fair values of cash, 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, 2018 and December 31, 2017, as they are short-term in nature or have interest rates that reset daily.

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, 2018 Carrying Amount | Level 2 Fair Value | At December 31, 2017 Carrying Amount | Level 2 Fair Value |
|---|---|---|---|---|
| PG&E Corporation | $ 350 | $ 348 | $ 350 | $ 350 |
| Utility | 16,693 | 17,723 | 17,090 | 19,128 |

Nuclear Decommissioning Trust Investments

The following table provides a summary of equity securities and available-for-sale debt securities:
(in millions)

| As of March 31, 2018 | Amortized Cost | Total Unrealized Gains | Total Unrealized Losses | Total Fair Value |
|---|---|---|---|---|
| Nuclear decommissioning trusts | | | | |
| Short-term investments | $ 28 | $ — | $ — | $28 |
| Global equity securities | 475 | 1,405 | (1 ) | 1,879 |
| Fixed-income securities | 1,355 | 39 | (19 ) | 1,375 |
| Total [1] | $ 1,858 | $ 1,444 | $ (20 ) | $3,282 |
| As of December 31, 2017 | | | | |
| Nuclear decommissioning trusts | | | | |
| Short-term investments | $ 23 | $ — | $ — | $23 |
| Global equity securities | 524 | 1,463 | (2 ) | 1,985 |
| Fixed-income securities | 1,252 | 51 | (8 ) | 1,295 |
| Total [1] | $ 1,799 | $ 1,514 | $ (10 ) | $3,303 |

[1] Represents amounts before deducting $440 million for the periods ended March 31, 2018 and December 31, 2017, primarily related to deferred taxes on appreciation of investment value.

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

| (in millions) | As of March 31, 2018 |
|---|---|
| Less than 1 year | $ 42 |
| 1–5 years | 438 |
| 5–10 years | 374 |
| More than 10 years | 521 |
| Total maturities of fixed-income securities | $ 1,375 |

The following table provides a summary of activity for fixed income and equity securities:

| | Three Months Ended March 31, | |
|---|---|---|
| (in millions) | 2018 | 2017 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | $494 | $470 |
| Gross realized gains on securities | 37 | 29 |
| Gross realized losses on securities | (4 ) | (5 ) |

NOTE 9: CONTINGENCIES AND COMMITMENTS

PG&E Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation.  A provision for a loss contingency is recorded when it is both probable that a liability has been incurred and the amount of the liability can be reasonably estimated.  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 may be materially affected by the outcome of the following matters.

Enforcement and Litigation Matters

Northern California Wildfires

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City. According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in Northern California that, in total, burned over 245,000 acres and destroyed an estimated 8,900 structures. The wildfires also resulted in 44 fatalities.

The Utility incurred costs of $259 million for service restoration and repair to the Utility's facilities (including $108 million in capital expenditures) through March 31, 2018, in connection with these fires. While the Utility believes that such costs are recoverable through CEMA, its CEMA requests are subject to CPUC approval. The Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to recover such costs.

The Northern California wildfires are under investigation by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. The Utility expects that Cal Fire will issue a report or reports stating its conclusions as to the sources of ignition of the fires and the ways that they progressed. Further, the CPUC's SED is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire-impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. Various other entities, including fire departments, may also be investigating certain of the fires. (For example, on February 3, 2018, it was reported that investigators with the Santa Rosa Fire Department had completed their investigation of two small fires that reportedly destroyed two homes and damaged one outbuilding and had concluded that the Utility's facilities, along with high wind and other factors, contributed to those fires.) It is uncertain when the investigations will be complete and whether Cal Fire will release any preliminary findings before its investigations are complete.

As of April 30, 2018, the Utility had submitted 23 electric incident reports to the CPUC associated with the Northern California wildfires where Cal Fire or the Utility has identified a site as potentially involving the Utility's facilities in its investigation and the property damage associated with each incident exceeded $50,000. The information contained in these reports is factual and preliminary, and does not reflect a determination of the causes of the fires. The investigations into the fires are ongoing.

If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the substantial cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, business interruption, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. California courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefited from such undertaking and based on the assumption that utilities have the ability to recover these costs from their customers. Further, courts could determine that the doctrine of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. There is no guarantee that the CPUC would authorize cost recovery even if a court decision were to determine that the doctrine of inverse condemnation applies. In addition to such claims for property damage, business interruption, interest and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. Further, the Utility could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations.

Given the incomplete investigations and the uncertainty as to the causes of the fires, PG&E Corporation and the Utility do not believe a loss is probable at this time. However, it is reasonably possible that facts could emerge through the course of the various investigations that lead PG&E Corporation and the Utility to believe that a loss is probable, resulting in an accrued liability in the future, the amount of which could be substantial. PG&E Corporation and the Utility currently are unable to reasonably estimate the amount of potential losses (or range of amounts) that they could incur given the preliminary stages of the investigations and the uncertainty regarding the extent and magnitude of potential damages. On January 31, 2018, the California Department of Insurance issued a press release announcing an update on property losses in connection with the October and December wildfires in California, stating that, as of such date, "insurers have received nearly 45,000 insurance claims totaling more than $11.79 billion in losses," of which approximately $10 billion relates to statewide claims from the October 2017 wildfires. The remaining amount relates to claims from the Southern California December 2017 wildfires. According to the California Department of Insurance, as of the date of the press release, more than 21,000 homes, 3,200 businesses, and more than 6,100 vehicles, watercraft, farm vehicles, and other equipment were damaged or destroyed by the October 2017 wildfires. PG&E Corporation and the Utility have not independently verified these estimates. The California Department of Insurance did not state in its press release whether it intends to provide updated estimates of losses in the future.

If the Utility's facilities are determined to be the cause of one or more of the Northern California wildfires, PG&E Corporation and the Utility could be liable for the related property losses and other damages. The California Department of Insurance January 31, 2018 press release reflects insured property losses only. The press release does not account for uninsured losses, interest, attorneys' fees, fire suppression costs, evacuation costs, medical expenses, personal injury and wrongful death damages or other costs. If the Utility were to be found liable for certain or all of such other costs and expenses, the amount of PG&E Corporation's and the Utility's liability could be higher than the approximately $10 billion in estimated insured property losses with respect to the wildfires that occurred in October 2017, depending on the extent of the damage in connection with such fire or fires. As a result, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

As of May 1, 2018, PG&E Corporation and the Utility are aware of more than 150 lawsuits representing approximately 2,500 plaintiffs, 6 of which seek to be certified as class actions, that have been filed against PG&E Corporation and the Utility in the Sonoma, Napa and San Francisco Counties Superior Courts. The lawsuits allege, among other things, negligence, inverse condemnation, trespass, and private nuisance. They principally assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the fires. The plaintiffs seek damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. In addition, insurance carriers who have made payments to their insureds for property damage arising out of the fires have filed 8 subrogation complaints in the San Francisco County Superior Court. These complaints allege, among other things, negligence, inverse condemnation, trespass and nuisance. The allegations are similar to the ones made by individual plaintiffs. Various government entities, including Mendocino, Napa and Sonoma Counties, have also asserted claims against PG&E Corporation and the Utility in the San Francisco County Superior Court based on the damages that these public entities allegedly suffered as a result of the fires. Such alleged damages include, among other things, loss of natural resources, loss of public parks, property damages and fire suppression costs. The causes of action and allegations are similar to the ones made by individual plaintiffs and the insurance carriers. On April 16, 2018, PG&E Corporation and the Utility submitted notices of claims against, among other government entities, Mendocino, Napa and Sonoma Counties, reserving their rights to pursue claims against these entities for contribution and equitable indemnity stemming from these entities' actions and inactions before and during the Northern California wildfires.

On October 31, 2017, a group of plaintiffs submitted a petition for coordination to the Chair of the Judicial Council of California and requested coordination of the litigation in the San Francisco Superior Court. On November 9, 2017, PG&E Corporation and the Utility submitted a petition for coordination to the Chair of the Judicial Council of California, and requested separate coordination in the counties in which the fires occurred. On January 4, 2018, the coordination motion judge of the San Francisco Superior Court entered an order granting coordination of the litigation in connection with the Northern California wildfires and recommending that the coordinated proceeding take place in the San Francisco Superior Court. On January 12, 2018, the Judicial Council of California accepted the coordination motion judge's recommendation and assigned the coordinated proceeding to San Francisco. The first case management conference took place on February 27, 2018. The individual plaintiffs, subrogation insurance carriers and certain government entities filed Master Complaints on March 12, 2018, and PG&E Corporation and the Utility filed Master Answers to those Master Complaints on March 16, 2018. PG&E Corporation and the Utility also filed on March 16, 2018, a legal challenge to the inverse condemnation causes of action in the Master Complaints. The court set a hearing on that challenge for May 18, 2018. The next case management conference will be scheduled at the May 18, 2018 hearing.

In addition, two derivative lawsuits for breach of fiduciary duties and unjust enrichment were filed in the San Francisco County Superior Court on November 16, 2017 and November 20, 2017, respectively. The first lawsuit is filed against the members of the Board of Directors and certain officers of PG&E Corporation. PG&E Corporation is identified as a nominal defendant in that action. The second lawsuit is filed against the members of the Board of Directors, certain former members of the Board of Directors, and certain officers of both PG&E Corporation and the Utility. PG&E Corporation and the Utility are identified as nominal defendants in that action. On February 14, 2018, the Court consolidated the two lawsuits, and, on April 13, 2018, the plaintiffs filed a consolidated complaint. After the parties reached an agreement regarding a stay of the derivative proceeding pending resolution of the tort actions described above and any regulatory proceeding relating to the Northern California wildfires, on April 24, 2018, the Court entered a stipulation and order to stay. The stay is subject to certain conditions regarding discovery.

PG&E Corporation and the Utility expect to be the subject of additional lawsuits in connection with the Northern California wildfires. The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved. The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Northern California wildfires in an aggregate amount of approximately $840 million, subject to an initial self-insured retention of $10 million per occurrence and further retentions of approximately $40 million per occurrence. In addition, coverage limits within the Utility's wildfire insurance policies could result in further material self-insured costs in the event each fire were deemed to be a separate occurrence under the terms of the insurance policies. If the Utility were to be found liable for one or more fires, the Utility's insurance could be insufficient to cover that liability, depending on the extent of the damage in connection with such fire or fires. Following the Northern California wildfires, PG&E Corporation reinstated its liability insurance in the amount of approximately $630 million for any potential future event.

In addition, it could take a number of years before the Utility’s final liability is known. The Utility may be unable to recover costs in excess of insurance through regulatory mechanisms and, even if such recovery is possible, it could take a number of years to resolve and a number of years thereafter to collect. PG&E Corporation and the Utility have considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover costs in excess of insurance through increases in rates and by collecting such rates in a timely manner, or any negative assessment by the Utility of the likelihood or timeliness of such recovery and collection, could have a material adverse effect on PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows.

Litigation and Regulatory Citations in Connection with the Butte Fire

In September 2015, a wildfire (known as the “Butte fire”) ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire’s report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures.  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/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

Third-Party Claims

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California, County of Sacramento.  Subrogation insurers also filed a separate master complaint on the same date.  The California Judicial Council had previously authorized the coordination of all cases in Sacramento County.  As of March 31, 2018, 79 known complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador. The complaints involve approximately 3,770 individual plaintiffs representing approximately 2,000 households and their insurance companies. These complaints are part of or are in the process of being added to the two master complaints. Plaintiffs seek to recover damages and other costs, principally based on the doctrine of inverse condemnation and negligence theory of liability. Plaintiffs also seek punitive damages. Prior to March 31, 2018, several plaintiffs dismissed the Utility's two vegetation management contractors from their complaints. The number of individual complaints and plaintiffs may still increase in the future, because the statute of limitations for property damage in connection with the Butte fire has not yet expired. (The statute of limitations for personal injury in connection with the Butte fire has expired.) The Utility continues mediating and settling cases.

In addition, on April 13, 2017, Cal Fire filed a complaint with the Superior Court of California, County of Calaveras, seeking to recover over $87 million for its costs incurred on the theory that the Utility and its vegetation management contractors were negligent, among other claims. On July 31, 2017, Cal Fire dismissed its complaint against Trees, Inc., one of the Utility's vegetation contractors. The Utility and Cal Fire are currently engaged in a mediation process.

Further, in May 2017, the OES indicated that it intends to bring a claim against the Utility that it estimates to be approximately $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the Butte fire.

Also, on February 20, 2018, the County of Calaveras filed suit against the Utility and the Utility’s vegetation management contractors. The County seeks to recover damages and other costs, based on the doctrine of inverse condemnation and negligence theory of liability. The County also seeks punitive damages. It had previously indicated that it intended to bring a claim against the Utility that it estimated to be approximately $85 million. On March 2, 2018, the County served a mediation demand seeking in excess of $167 million. This claim includes costs that the County of Calaveras allegedly incurred or expects to incur for infrastructure damage, erosion control, and other costs related to the Butte fire. The Utility and the County of Calaveras are currently engaged in a mediation process.

On April 28, 2017, the Utility moved for summary adjudication on plaintiffs’ claims for punitive damages. On August 10, 2017, the Court denied the Utility’s motion on the grounds that plaintiffs might be able to show conscious disregard for public safety based on the fact that the Utility relied on contractors to fulfill their contractual obligation to hire and train qualified employees. On August 16, 2017, the Utility filed a writ with the Court of Appeal challenging the trial court's ruling on punitive damages. The Court of Appeal accepted the writ on September 15, 2017, and ordered the trial court and plaintiffs to show cause why the relief requested by the Utility should not be granted. Briefing on the writ was completed as of January 2, 2018. The Utility sought expedited review of the motion. On April 4, 2018, the Court of Appeal indicated that it is prepared to issue a decision without oral argument. On April 13, 2018 and April 16, 2018, respectively, the plaintiffs and the Utility requested oral argument, which is now scheduled for June 22, 2018.

On June 22, 2017, the Superior Court of California, County of Sacramento ruled on a motion of several plaintiffs and found that the doctrine of inverse condemnation applies to the Utility with respect to the Butte fire. The Court held, among other things, that the Utility had failed to put forth any evidence to support its contention that the CPUC would not allow the Utility to pass on its inverse condemnation liability through rate increases. While the ruling is binding only between the Utility and the plaintiffs in the coordination proceeding at the time of the ruling, others could file lawsuits and make similar claims. On January 4, 2018, the Utility filed with the Court a renewed motion for a legal determination of inverse condemnation liability, citing the November 30, 2017 CPUC decision denying the San Diego Gas & Electric Company application to recover wildfire costs in excess of insurance, and the CPUC declaration that it will not automatically allow utilities to spread inverse condemnation losses through rate increases.

On May 1, 2018, the Court issued its ruling on the Utility's renewed motion in which the Court affirmed, with minor changes, its tentative ruling dated April 25, 2018. The Court determined that it is bound by earlier holdings of two appellate courts decisions, Barham and Pacific Bell. Further, the Court stated that the Utility's constitutional arguments should be made to the appellate courts and suggested that, to the extent the Utility raises the public policy implications of the November 30, 2017 CPUC decision in the San Diego Gas & Electric Company cost recovery proceeding, these arguments should be addressed to the Legislature or CPUC. The next case management conference is scheduled for June 7, 2018. The Utility intends to file a writ seeking review of this decision. No trial date is pending.

Estimated Losses from Third-Party Claims

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the doctrine of inverse condemnation.

In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility is found to have been negligent. While the Utility believes it was not negligent, there can be no assurance that a court or jury would agree with the Utility.

The Utility currently believes that it is probable that it will incur a loss of at least $1.1 billion in connection with the Butte fire. This amount is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and certain other damages, but does not include punitive damages for which the Utility could be liable. In addition, while this amount includes the Utility's early assumptions about fire suppression costs (including its assessment of the Cal Fire loss) and the County of Calaveras claim, it does not include any significant portion of the estimated claim from the OES. The Utility still does not have sufficient information to reasonably estimate any liability it may have for that additional claim.

The Utility currently is unable to reasonably estimate the upper end of the range of losses due to uncertainties related to the applicability of inverse condemnation and punitive damages and because it has insufficient information on the claims of over 600 households who have asserted claims, the claim from the OES, as well as claims from any other households that may be brought before the statute of limitations for property damage expires. The process for estimating costs associated with claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs, results from the ongoing mediation and settlement process, review of the potential claim from the OES, outcomes of future court or jury decisions, and information about damages, including punitive damages, for which the Utility could be liable, management estimates and assumptions regarding the financial impact of the Butte fire may result in material increases to the loss accrued.

The following table presents changes in the third-party claims liability since December 31, 2015. The balance for the third-party claims liability is included in Other current liabilities in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets:

| Loss Accrual (in millions) | |
|---|---|
| Balance at December 31, 2015 | $— |
| Accrued losses | 750 |
| Payments [1] | (60) |
| Balance at December 31, 2016 | 690 |
| Accrued losses | 350 |
| Payments [1] | (479) |
| Balance at December 31, 2017 | 561 |
| Accrued losses | — |
| Payments [1] | (118 ) |
| Balance at March 31, 2018 | $443 |

[1] As of March 31, 2018 the Utility entered into settlement agreements in connection with the Butte fire corresponding to approximately $734 million of which $657 million has been paid by the Utility.

In addition to the amounts reflected in the table above, the Utility has incurred cumulative legal expenses of $99 million in connection with the Butte fire. For the three months ended March 31, 2018, the Utility incurred legal expenses in connection with the Butte fire of $12 million.

Loss Recoveries

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of $922 million. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. Through March 31, 2018, the Utility recorded $922 million for probable insurance recoveries in connection with losses related to the Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, the Utility has received $60 million in cumulative reimbursements from the insurance policies of its vegetation management contractors (excluded from the table below), including $7 million received in the three months ended March 31, 2018. Recoveries of additional amounts under the insurance policies of the Utility's vegetation management contractors, including policies where the Utility is listed as an additional insured, are uncertain.

The following table presents changes in the insurance receivable since December 31, 2015. The balance for the insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets:

| Insurance Receivable (in millions) | |
|---|---|
| Balance at December 31, 2015 | $— |
| Accrued insurance recoveries | 625 |
| Reimbursements | (50) |
| Balance at December 31, 2016 | 575 |
| Accrued insurance recoveries | 297 |
| Reimbursements | (276) |
| Balance at December 31, 2017 | 596 |
| Accrued insurance recoveries | — |
| Reimbursements | (197 ) |
| Balance at March 31, 2018 | $399 |

In April 2018, the Utility received another $31 million in insurance reimbursements.

If the Utility records losses in connection with claims relating to the Butte fire that materially exceed the amount the Utility accrued for these liabilities, PG&E Corporation's and the Utility's financial condition, results of operations, or cash flows could be materially affected in the reporting periods during which additional charges are recorded.

Regulatory Citations

On April 25, 2017, the SED issued two citations to the Utility in connection with the Butte fire, totaling $8.3 million. The SED's investigation found that neither the Utility nor its vegetation management contractors took appropriate steps to prevent a gray pine tree from leaning and contacting the Utility's electric line, which created an unsafe and dangerous condition that resulted in that tree leaning and making contact with the electric line, thus causing a fire. The Utility paid the citations in June 2017.

Enforcement Matters

In 2014, both the U.S. Attorney's Office in San Francisco and the California Attorney General's office opened investigations into matters related to allegedly improper communication between the Utility and CPUC personnel. The Utility has cooperated with those investigations. It is uncertain whether any charges will be brought against the Utility as a result of these investigations.

Regulatory Proceedings

Order Instituting an Investigation into Compliance with Ex Parte Communication Rules

On April 26, 2018, the CPUC approved the revised proposed decision issued on April 3, 2018, adopting the settlement agreement jointly submitted to the CPUC on March 28, 2017, as modified (the "settlement agreement") by the Utility, the Cities of San Bruno and San Carlos, the ORA, the SED, and TURN.

The decision results in a total penalty of $97.5 million comprised of: (1) a $12 million payment to the California General Fund, (2) forgoing collection of $63.5 million of GT&S revenue requirements for the years 2018 ($31.75 million) and 2019 ($31.75 million), (3) a $10 million one-time revenue requirement adjustment to be amortized in equivalent annual amounts over the Utility's next GRC cycle (i.e., the GRC following the 2017 GRC), and (4) compensation payments to the Cities of San Bruno and San Carlos in a total amount of $12 million ($6 million to each city). In addition, the settlement agreement provides for certain non-financial remedies, including enhanced noticing obligations between the Utility and CPUC decision-makers, as well as certification of employee training on the CPUC ex parte communication rules. Under the terms of the settlement agreement, customers will bear no costs associated with the financial remedies set forth above. The CPUC also ordered a second phase in this proceeding to determine if any of the additional communications that the Utility reported to the CPUC on September 21, 2017 violate the CPUC ex-parte rules.

The Utility is unable to predict the timing and outcome of the second phase in this proceeding.

At March 31, 2018, PG&E Corporation's and the Utility's Condensed Consolidated Balance Sheets include a $8 million accrual for a portion of the 2018 GT&S revenue requirement reduction and an accrual of the $24 million payable to the California General Fund and the Cities of San Bruno and San Carlos. In accordance with accounting rules, adjustments related to revenue requirements are recorded in the periods in which they are incurred.

For more information about the proceeding, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

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. The CPUC has delegated authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. There are a number of audit findings, as well as other potential violations identified through various investigations and the Utility's self-reported non-compliance with laws and regulations, on which the SED has yet to act. Under both the gas and electric programs, the SED has discretion whether to issue a penalty for each violation.

If the SED assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000, with an administrative limit of $8 million per citation issued. The SED may, at its discretion, impose penalties on a daily basis, or on less than a daily basis, for violations that continued for more than one day. The SED also has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The SED also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged. Historically, the SED has exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed. In the past, 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 CPUC can also open an OII and levy additional fines even after the SED has issued a citation.

The Utility is unable to reasonably estimate the amount or range of future charges as a result of SED investigations or any proceedings that could be commenced in connection with potential violations of electric and natural gas laws and regulations.

Other Matters

PG&E Corporation and the Utility are subject to various claims, lawsuits, and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under “Enforcement and Litigation Matters”) totaled $89 million at March 31, 2018, and $86 million at December 31, 2017. 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.

Disallowance of Plant Costs

2015 GT&S Rate Case Capital Disallowances

On June 23, 2016, the CPUC approved a final phase one decision in the Utility's 2015 GT&S rate case. The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted in the prior GT&S rate case. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. Additional charges may be required in the future based on the Utility's ability to manage its capital spending and on the outcome of the CPUC's audit of 2011 through 2014 capital spending. Capital disallowances are reflected in operating and maintenance expenses in the Condensed Consolidated Statements of Income. For more information, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

Environmental Remediation Contingencies

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

| | Balance at | |
|---|---|---|
| (in millions) | March 31, 2018 | December 31, 2017 |
| Topock natural gas compressor station | $342 | $ 334 |
| Hinkley natural gas compressor station | 144 | 147 |
| Former manufactured gas plant sites owned by the Utility or third parties [(1)] | 329 | 320 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites [(2)] | 113 | 115 |
| Fossil fuel-fired generation facilities and sites [(3)] | 157 | 123 |
| Total environmental remediation liability | $1,085 | $ 1,039 |

[(1)] Primarily driven by the following sites: Vallejo, San Francisco East Harbor, Napa, and San Francisco North Beach.
[(2)] Primarily driven by the Shell Pond site.
[(3)] Primarily driven by the San Francisco Potrero Power Plant.

The Utility's gas compressor stations, former manufactured gas plant sites, power plant sites, gas gathering sites, and sites used by the Utility for the storage, recycling, and disposal of potentially hazardous substances are subject to requirements issued by the Environmental Protection Agency under the federal Resource Conservation and Recovery Act and/or other federal and state hazardous waste laws. The Utility has a comprehensive program in place designed to comply with federal, state, and local laws and regulations related to hazardous materials, waste, remediation activities, and other environmental requirements. The Utility assesses and monitors, on an ongoing basis, measures that may be necessary to comply with these laws and regulations and implements changes to its program as deemed appropriate. The Utility's remediation activities are overseen by the DTSC, several California regional water quality control boards, and various other federal, state, and local agencies.

The Utility's environmental remediation liability at March 31, 2018, reflects its best estimate of probable future costs associated with its final remediation plans. Future costs will depend on many factors, including the extent of work necessary to implement final remediation plans and the Utility's time frame for remediation. 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, financial condition and cash flows during the period in which they are recorded. At March 31, 2018, the Utility expected to recover $737 million of its environmental remediation liability for certain sites through various ratemaking mechanisms authorized by the CPUC.

For more information, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

Natural Gas Compressor Station Sites

The Utility is legally responsible for remediating groundwater contamination caused by hexavalent chromium used in the past at the Utility’s natural gas compressor stations. The Utility is also required to take measures to abate the effects of the contamination on the environment.

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the California DTSC 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. On December 21, 2017, the DTSC issued its final environmental impact report. The environmental impact report includes requirements related to conditions of work that have been anticipated or previously required and are accounted for in the current environmental remediation liability. The Utility's undiscounted future costs associated with the Topock site may increase by as much as $293 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Topock site are expected to be recovered through the HSM, where 90% of the costs are recovered in rates.

Hinkley Site

The Utility has been implementing remediation measures at the Hinkley site to reduce the mass of the chromium plume in groundwater 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 California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a clean-up and abatement order directing the Utility 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 sets plume capture requirements, requires a monitoring and reporting program, and includes deadlines for the Utility to meet interim cleanup targets. The United States Geological Survey team is currently conducting a background study on the site to better define the chromium plume boundaries. The background study is expected to be finalized in 2019. The Utility's undiscounted future costs associated with the Hinkley site may increase by as much as $146 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

Former Manufactured Gas Plants

Former MGPs used coal and oil to produce gas for use by the Utility's customers in the past. The by-products and residues of this process were often disposed of at the MGPs themselves. The Utility has undertaken a program to manage the residues left behind as a result of the manufacturing process; many of the sites in the program have been addressed. The Utility's undiscounted future costs associated with MGP sites may increase by as much as $340 million if the extent of contamination or necessary remediation is greater than anticipated. The costs associated with environmental remediation at the MGP sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Utility-Owned Generation Facilities and Third-Party Disposal Sites

Utility-owned generation facilities and third-party disposal sites are long-term projects that are undergoing a remediation process. The Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as $142 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the Utility-owned generation facilities and third-party disposal sites are recovered through the HSM, where 90% of the costs are recovered in rates.

Fossil Fuel-Fired Generation Sites

In 1998 the Utility divested its generation power plant business as part of generation deregulation. Although the Utility has sold its fossil-fueled power plants, the Utility has retained the environmental remediation liability associated with each site. The Utility’s undiscounted future costs associated with fossil fuel-fired generation sites may increase by as much as $106 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the fossil fuel-fired sites will not be recovered through rates.

Nuclear Insurance

The Utility maintains multiple insurance policies through NEIL and European Mutual Association for Nuclear Insurance, covering nuclear or non- nuclear events at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. 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, 2018, the current maximum aggregate annual retrospective premium obligation for the Utility would be approximately $47 million. If European Mutual Association for Nuclear Insurance losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $3 million, as of April 1, 2018. For more information about the Utility's nuclear insurance coverage, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 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. While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility has entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Under these settlement agreements, amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

At December 31, 2017, the Consolidated Balance Sheets reflected $243 million in net claims within Disputed claims and customer refunds. There were no significant changes to this balance during the three months ended March 31, 2018. The Utility is uncertain when or how the remaining net disputed claims liability will be resolved.

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 audits. As of March 31, 2018, it is reasonably possible that unrecognized tax benefits will decrease by approximately $20 million within the next 12 months. PG&E Corporation and the Utility believe that the majority of the decrease will not impact net income.

Tax Cuts and Jobs Act of 2017

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35% to 21% beginning on January 1, 2018 and eliminated bonus depreciation for utilities. The Tax Act required PG&E Corporation and the Utility to re-measure all existing deferred income tax assets and liabilities to reflect the reduction in the federal tax rate. PG&E Corporation and the Utility recorded reasonable estimates to reflect the impacts of the Tax Act and recorded provisional amounts, in accordance with rules issued by the SEC in Staff Accounting Bulletin No. 118, for the re-measurement of deferred tax balances as of December 31, 2017. There were no material updates to these estimates in the three months ended March 31, 2018.

On March 30, 2018, the Utility submitted to the CPUC PFMs of the CPUC's final decisions in the Utility's 2017 GRC, and the 2015 GT&S rate case. Additionally, the Utility submitted updated testimony in connection with the 2019 GT&S rate case. These submittals reflect the effects of the Tax Act on these rate cases. On an aggregate basis from these submittals, the Utility anticipates an annual reduction to revenue requirements of approximately $325 million starting in 2018, and incremental increases to rate base of approximately $271 million for 2018 (including the impact of the pending private letter ruling advice letter), and $613 million for 2019. The incremental increases to rate base are due primarily to the elimination of bonus depreciation. The Utility also expects to reflect an annual revenue requirement reduction, starting in 2018, of approximately $125 million from other rate cases, including the TO19 rate case. The associated rate base increases are approximately $100 million in 2018 and $200 million in 2019. The Utility is unable to predict the timing and outcome of the CPUC decisions in connection with these submittals.

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, 2017, the Utility had undiscounted future expected obligations of approximately $44 billion. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.) The Utility has not entered into any new material commitments during the three months ended March 31, 2018.

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 serving 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, terms, and conditions of service for the Utility's electricity and natural gas distribution operations, electric generation, and natural gas transportation and storage. The FERC has jurisdiction over the rates and terms and conditions of service governing the Utility's electric transmission operations and interstate natural gas transportation contracts. The NRC oversees the licensing, construction, operation, and decommissioning of the Utility's nuclear generation facilities. The Utility is also 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 also should be read in conjunction with the 2017 Form 10-K.

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City (the "Northern California wildfires"). According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in Northern California that, in total, burned over 245,000 acres and destroyed an estimated 8,900 structures. The wildfires also resulted in 44 fatalities.

The Northern California wildfires are under investigation by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. The Utility expects that Cal Fire will issue a report or reports stating its conclusions as to the sources of ignition of the fires and the ways that they progressed. Further, the CPUC's SED is conducting investigations to assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire-impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. It is uncertain when the investigations will be complete and whether Cal Fire will release any preliminary findings before its investigations are complete.

PG&E Corporation and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires. See Item 1A. Risk Factors in the 2017 Form 10-K.

Tax Cuts and Jobs Act of 2017

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35% to 21% beginning on January 1, 2018 and eliminated bonus depreciation for utilities. The Tax Act required PG&E Corporation and the Utility to re-measure all existing deferred income tax assets and liabilities to reflect the reduction in the federal tax rate. PG&E Corporation and the Utility recorded reasonable estimates to reflect the impacts of the Tax Act and recorded provisional amounts, in accordance with rules issued by the SEC in Staff Accounting Bulletin No. 118, for the re-measurement of deferred tax balances as of December 31, 2017. There were no material updates to these estimates in the three months ended March 31, 2018.

On March 30, 2018, the Utility submitted to the CPUC PFMs of the CPUC's final decisions in the Utility's 2017 GRC, and the 2015 GT&S rate case. Additionally, the Utility submitted updated testimony in connection with the 2019 GT&S rate case. These submittals reflect the effects of the Tax Act on these rate cases. On an aggregate basis from these submittals, the Utility anticipates an annual reduction to revenue requirements of approximately $325 million starting in 2018, and incremental increases to rate base of approximately $271 million for 2018 (including the impact of the pending private letter ruling advice letter), and $613 million for 2019. The incremental increases to rate base are due primarily to the elimination of bonus depreciation. The Utility also expects to reflect an annual revenue requirement reduction, starting in 2018, of approximately $125 million from other rate cases, including the TO19 rate case. The associated rate base increases are approximately $100 million in 2018 and $200 million in 2019. The Utility is unable to predict the timing and outcome of the CPUC decisions in connection with these submittals.

Summary of Changes in Net Income and Earnings per Share

The tables below include a summary reconciliation of PG&E Corporation's consolidated income available for common shareholders and EPS to earnings from operations and EPS based on earnings from operations for three months ended March 31, 2018 as compared to the same period in 2017 and a summary reconciliation of the key drivers of PG&E Corporation's earnings from operations and EPS based on earnings from operations for the three months ended March 31, 2018 as compared to the same period in 2017. "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, | | | |
|---|---|---|---|---|
| | Earnings | | Earnings per Common Share (Diluted) | |
| (in millions, except per share amounts) | 2018 | 2017 | 2018 | 2017 |
| PG&E Corporation's Earnings on a GAAP basis | $442 | $576 | $0.86 | $1.13 |
| Items Impacting Comparability: (1) | | | | |
| Northern California wildfire-related costs (2) | 15 | — | 0.03 | — |
| Pipeline-related expenses (3) | 7 | 16 | 0.01 | 0.03 |
| Butte fire-related costs, net of insurance (4) | 4 | 2 | 0.01 | — |
| Legal and regulatory-related expenses | — | 2 | — | — |
| Fines and penalties | — | 36 | — | 0.07 |
| GT&S revenue timing impact | — | (88 ) | — | (0.17 ) |
| PG&E Corporation's Earnings from Operations (5) | $468 | $544 | $0.91 | $1.06 |

All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 27.98 percent for 2018 and 40.75 percent for 2017, except for certain fines and penalties in 2017.

(1) "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.

[2] The Utility incurred costs of $21 million (before the tax impact of $6 million) during the three months ended March 31, 2018, for legal and other costs associated with the Northern California wildfires.
[3] The Utility incurred costs of $10 million (before the tax impact of $3 million) during the three months ended March 31, 2018 for pipeline-related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way.
[4] The Utility incurred costs, net of insurance, of $5 million (before the tax impact of $1 million) during the three months ended March 31, 2018 associated with the Butte fire. The Utility incurred charges of $12 million (before the tax impact of $3 million) during the three months ended March 31, 2018 for legal costs. These costs were partially offset by $7 million (before the tax impact of $2 million) recorded during the three months ended March 31, 2018, for contractor insurance recoveries.
[5] “Earnings from operations” is a non-GAAP financial measure.

Reconciliation of Key Drivers of PG&E Corporation's EPS from Operations (Non-GAAP):

| | Three Months Ended March 31, | |
|---|---|---|
| (in millions, except per share amounts) | Earnings | Earnings per Common Share (Diluted) |
| 2017 Earnings from Operations [1] | $544 | $ 1.06 |
| Growth in rate base earnings [2] | 42 | 0.08 |
| Timing of 2017 GRC cost recovery [3] | 18 | 0.03 |
| Tax impact of stock compensation [4] | (44 ) | (0.08 ) |
| Timing of nuclear refueling outages | (31 ) | (0.06 ) |
| Timing of taxes [5] | (25 ) | (0.05 ) |
| Decrease in authorized return on equity [6] | (7 ) | (0.01 ) |
| Increase in shares outstanding | — | (0.01 ) |
| Miscellaneous | (29 ) | (0.05 ) |
| 2018 Earnings from Operations [1] | $468 | $ 0.91 |

[1] See first table above for a reconciliation of EPS on a GAAP basis to EPS from Operations. All amounts presented in the table above are tax adjusted at PG&E Corporation's statutory tax rate of 27.98 percent for 2018 and 40.75 percent for 2017, except for the tax impact of stock compensation. See Footnote 4 below.
[2] Represents the impact of the increase in rate base authorized in various rate cases, including the 2017 GRC, during the three months ended March 31, 2018, as compared to the same period in 2017. The CPUC issued its final decision in the 2017 GRC proceeding on May 11, 2017, delaying recognition of the 2017 revenue increase until the second quarter of 2017.
[3] Represents revenue for GRC-related capital costs (depreciation and interest) in the first quarter of 2018, with no similar impact in 2017. The CPUC issued its final decision in the 2017 GRC on May 11, 2017, delaying recognition of the 2017 revenue increase until the second quarter of 2017.
[4] Represents the impact of income taxes related to share-based compensation awards under the Long-Term Incentive Plan that vested during the three months ended March 31, 2018, as compared to the same period in 2017.
[5] Represents the timing of taxes reportable in quarterly statements in accordance with Accounting Standards Codification 740, Income Taxes, and results from variances in the percentage of quarterly earnings to annual earnings.
[6] Represents the decrease in ROE from 10.40 percent in 2017 to 10.25 percent in 2018 as a result of the 2017 CPUC final decision approving an additional extension to the original 2013 Cost of Capital decision.

Key Factors Affecting Financial Results

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

- The Impact of the Northern California Wildfires. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the Northern California wildfires. The Utility incurred costs of $259 million for service restoration and repair to the Utility's facilities (including $108 million in capital expenditures) through March 31, 2018, in connection with these fires. PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to recover such costs through CEMA. If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the substantial cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, business interruption, interest, and attorneys' fees without having been found negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. In addition to such claims for property damage, business interruption, interest and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material effect on PG&E Corporation and the Utility. Further, the Utility could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- The Applicability of the Doctrine of Inverse Condemnation in PG&E Corporation and the Utility's Wildfire Litigation. The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation and the Utility are subject, could expose PG&E Corporation and the Utility to substantial liabilities from such litigation and materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows. Although the imposition of liability is premised on the assumption that utilities have the ability to recover these costs from their customers, there can be no guarantee that the CPUC would authorize cost recovery even if a court decision imposes liability under the doctrine of inverse condemnation. In November 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it incurred as a result of the doctrine of inverse condemnation, holding that the inverse condemnation principles of strict liability are not relevant to the CPUC's prudent manager standard. That determination is being challenged by San Diego Gas & Electric as well as by the Utility and Southern California Edison. PG&E Corporation and the Utility are also challenging the appropriateness of applying inverse condemnation to investor-owned utilities in the Butte Fire litigation and the Northern California wildfires litigation. In addition, the applicability of inverse condemnation could be impacted by actions of the California state legislature which addressed the 2017 wildfires through multiple committee hearings during the first quarter of 2018. On March 13, 2018, Governor Brown along with Democratic and Republican legislative leaders also issued a joint statement indicating an intent to partner on solutions to protect Californians from the threat of natural disasters and climate change, including an update to liability rules and regulations for utility services. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- The Success of the Utility's Community Wildfire Safety Program. The Utility has developed a comprehensive community wildfire safety program in coordination with first responders, civic and community leaders, and customers to help reduce wildfire threats and improve safety as a result of climate-driven wildfires and extreme weather events. The community safety wildfire program focuses on three areas: bolstering wildfire prevention and emergency response; working with communities on new and enhanced safety measures; and, longer term, hardening the electric system and integrating new technologies to increase grid resilience.

- The Tax Cut and Jobs Act. On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35% to 21% beginning on January 1, 2018 and eliminates bonus depreciation for utilities. On March, 30, 2018, the Utility submitted PFMs of the CPUC's final decisions in the Utility's 2017 GRC, and the 2015 GT&S rate case. Additionally, the Utility submitted updated testimony in connection with the 2019 GT&S rate case. These submittals reflect the effects of the Tax Act on these rate cases. On May 14, 2018, the Utility will file a proposal to reflect the impact of the Tax Act on its TO tariff rates effective, March 1, 2018, in the resolution of the TO19 rate case. The Utility is unable to predict the timing and outcome of the CPUC's and FERC's decisions in connection with these submittals. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- The Outcome of Enforcement, Litigation, and Regulatory Matters. The Utility’s financial results may continue to be impacted by the outcome of current and future enforcement, litigation, and regulatory matters, including the impact of the Northern California wildfires, the Butte fire, the safety culture OII and any related fines, penalties, or other ratemaking tools that could be imposed by the CPUC, including as a result of phase two of the proceeding, the outcome of phase two of the ex parte OII, the potential recommendations that the third-party monitor (retained by the Utility in the first quarter of 2017 as part of its compliance with the sentencing terms of the Utility’s January 27, 2017 federal criminal conviction) may make, and potential penalties in connection with the Utility’s safety and other self-reports. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

- The Timing and Outcome of Ratemaking Proceedings. The Utility’s financial results may be impacted by the timing and outcome of its 2019 GT&S rate case, FERC TO18 and TO19 rate cases, as well as the recent remand decision by the Ninth Circuit regarding an ROE incentive adder for transmission facilities, and the 2018 CEMA filing. The outcome of regulatory proceedings can be affected by many factors, including intervening parties’ testimonies, potential rate impacts, the Utility’s reputation, the regulatory and political environments, and other factors. (See “Regulatory Matters – 2019 Gas Transmission and Storage Rate Case” and “Regulatory Matters – FERC Transmission Owner Rate Cases”.)

- The Ability of the Utility to Control and Recover Operating Costs and Capital Expenditures. In any given year the Utility’s ability to earn its authorized rate of return depends on its ability to manage costs within the amounts authorized in rate case decisions. The Utility forecasts that in 2018 it will incur unrecovered pipeline-related expenses ranging from $35 million to $60 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. Also, the CPUC decision in the Utility’s 2015 GT&S rate case established various cost caps that will increase the risk of overspend over the rate case cycle through 2018.

- The Amount and Timing of the Utility's Financing Needs. PG&E Corporation’s and the Utility’s ability to access the capital markets, ability to borrow under its loan financing arrangements, and the terms and rates of future financings could be materially affected by the outcome of, or market perception of, the matters discussed in Note 9 of the Notes to the Condensed Consolidated Financial Statements, including liabilities, if any, incurred in relation to the Northern California wildfires, adverse effects on PG&E Corporation’s and the Utility’s ability to comply with consolidated debt to total capitalization ratio covenants in their financing arrangements and regulatory capital structure requirements, adverse changes in their respective credit ratings, general economic and market conditions, and other factors. 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, 2018, PG&E Corporation issued $35 million of common stock and made no equity contributions to the Utility. PG&E Corporation may seek to issue additional equity to pay claims, losses, fines, and penalties that may be required by the outcome of litigation and enforcement matters. Additional issuances of equity, if any, could have a material dilutive impact on PG&E Corporation’s EPS.

- Changes in the Utility Industry. The Utility is committed to delivering safe, reliable, sustainable, and affordable electric and gas services to its customers. Increasing demands from state laws and policies relating to increased renewable energy resources, the reduction of GHG emissions, the expansion of energy efficiency programs, the development and widespread deployment of distributed generation and self-generation resources, and the development of energy storage technologies have increased pressure on the Utility to achieve efficiencies in its operations while continuing to provide customers with safe, reliable, and affordable service. The utility industry is also undergoing transformative change driven by technological advancements enabling customer choice (for example, customer-owned generation and energy storage) and state climate policy supporting a decarbonized economy. California’s environmental policy objectives are accelerating the pace and scope of the industry change. The electric grid is a critical enabler of the adoption of new energy technologies that support California's climate change and GHG reduction objectives, which continue to be publicly supported by California policy makers notwithstanding a recent change in the federal approach to such matters. In order to enable the California clean energy economy, sustained investments are required in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, EV infrastructure, and state infrastructure modernization (e.g. rail and water projects). In addition, these changes brought about by technological advancements and climate policy may cause a reduction in natural gas usage and increase natural gas costs. The combination of reduced natural gas load and increased costs could result in higher natural gas customer bills and potential cost recovery risk.

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, or that could cause future results to differ from historical results, see "Item 1A. Risk Factors" in the 2017 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 that are based on current estimates, expectations, and projections about future events and assumptions regarding these events and management's knowledge of facts as of the date of this report. See the section entitled "Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially. PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

RESULTS OF OPERATIONS

PG&E Corporation

The consolidated results of operations consist primarily of results related to the Utility, which are discussed in the "Utility" section below. The following table provides a summary of net income available for common shareholders for the three months ended March 31, 2018 and 2017:

| | Three Months Ended March 31, | |
|---|---|---|
| (in millions) | 2018 | 2017 |
| Consolidated Total | $442 | $576 |
| PG&E Corporation | (7) | 10 |
| Utility | $449 | $566 |

PG&E Corporation's net income (loss) primarily consists of income taxes and interest expense on long-term debt. The decrease in PG&E Corporation's net income for the three months ended March 31, 2018 as compared to the same period in 2017 is primarily due to the impact of income taxes.

Utility

The table below shows certain items from the Utility's Condensed Consolidated Statements of Income for the three months ended March 31, 2018 and 2017. 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.

| (in millions) | Three Months Ended March 31, 2018 Revenues/Costs: That Impacted Earnings | That Did Not Impact Earnings | Total Utility | Three Months Ended March 31, 2017 Revenues/Costs: That Impacted Earnings | That Did Not Impact Earnings | Total Utility |
|---|---|---|---|---|---|---|
| Electric operating revenues | $1,937 | $ 1,014 | $2,951 | $1,982 | $ 1,085 | $3,067 |
| Natural gas operating revenues | 738 | 367 | 1,105 | 777 | 427 | 1,204 |
| Total operating revenues | 2,675 | 1,381 | 4,056 | 2,759 | 1,512 | 4,271 |
| Cost of electricity | — | 819 | 819 | — | 847 | 847 |
| Cost of natural gas | — | 289 | 289 | — | 325 | 325 |
| Operating and maintenance | 1,244 | 353 | 1,597 | 1,164 | 354 | 1,518 |
| Depreciation, amortization, and decommissioning | 752 | — | 752 | 712 | — | 712 |
| Total operating expenses | 1,996 | 1,461 | 3,457 | 1,876 | 1,526 | 3,402 |
| Operating income | 679 | (80) | 599 | 883 | (14) | 869 |
| Interest income | 9 | — | 9 | 5 | — | 5 |
| Interest expense | (217) | — | (217) | (216) | — | (216) |
| Other income, net | 29 | 80 | 109 | 17 | 14 | 31 |
| Income before income taxes | $500 | $— | $500 | $689 | $— | $689 |
| Income tax provision [1] | | | 48 | | | 120 |
| Net income | | | 452 | | | 569 |
| Preferred stock dividend requirement [1] | | | 3 | | | 3 |
| Income Available for Common Stock | | | $449 | | | $566 |

[1] These items impacted earnings for the three months ended March 31, 2018 and 2017.

Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for the three months ended March 31, 2018 and 2017, 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 decreased by $84 million, or 3%, in the three months ended March 31, 2018, compared to the same period in 2017, primarily due to $102 million in retroactive base revenues authorized in the 2015 GT&S rate case recognized in the three months ended March 31, 2017, with no similar revenues recorded in the same period in 2018 and $81 million recorded in the three months ended March 31, 2018, as provisions for rate refunds for the 2017 GRC and the 2015 GT&S rate case as a result of the Tax Act, with no corresponding revenue reductions in the same period in 2017. These revenue reductions were partially offset by increased base revenues authorized in the 2017 GRC, 2015 GT&S rate case, and the TO18 rate case.

Operating and Maintenance

The Utility’s operating and maintenance expenses that impacted earnings increased by $80 million, or 7%, in the three months ended March 31, 2018 compared to the same period in 2017 primarily due an increase in environmental remediation expenses at the San Francisco Potrero Power Plant of approximately $40 million in the first quarter of 2018 as compared to the same period in 2017 and $32 million in costs related to higher premiums for liability insurance incurred during the first quarter of 2018 as compared to the same period in 2017. Additionally, the Utility incurred $21 million in legal and other costs associated with the Northern California wildfires in the three months ended March 31, 2018 with no corresponding costs in the same period in 2017.

The Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires and any additional charges associated with costs related to the Butte fire.  (See "Item 1A. Risk Factors" in the 2017 Form 10-K and Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of this Form 10-Q.)

Depreciation, Amortization, and Decommissioning

The Utility’s depreciation, amortization, and decommissioning expenses that impacted earnings increased by $40 million, or 6%, in the three months ended March 31, 2018 compared to the same period in 2017 primarily due to capital additions and the delay in the 2017 GRC rate case decision.

Interest Income and Interest Expense

There were no material changes to interest income and interest expense that impacted earnings for the periods presented.

Other Income, Net

There were no material changes to other income, net, that impacted earnings for the periods presented.

Income Tax Provision

The income tax provision decreased by $72 million, or 60%, in the three months ended March 31, 2018 as compared to the same period in 2017.  The effective tax rates for the three months ended March 31, 2018 and 2017 were 9.6% and 17.4%, respectively.  The decrease in the income tax provision and the effective tax rate is primarily the result of the decrease in the corporate income tax rate from 35% to 21% as a result of the Tax Act, partially offset by a reduction in tax benefits related to share-based compensation.

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

| | Three Months Ended March 31, | |
|---|---|---|
| | 2018 | 2017 |
| Federal statutory income tax rate | 21.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | |
| State income tax (net of federal benefit) [(1)] | 2.3 % | 1.8 % |
| Effect of regulatory treatment of fixed asset differences [(2)] | (16.5)% | (13.1)% |
| Tax credits | (0.6 )% | (0.4 )% |
| Other, net [(3)] | 3.4 % | (5.9 )% |
| Effective tax rate | 9.6 % | 17.4 % |

[(1)] Includes the effect of state flow-through ratemaking treatment.
[(2)] Includes the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision (impacting 2017) & the 2017 GRC decision (impacting 2018), and by the 2015 GT&S decision (impacting both periods presented). All amounts are impacted by the level of income before income taxes. The 2014 GRC, 2017 GRC, and 2015 GT&S rate case decisions authorized revenue requirements that reflect flow-through ratemaking for temporary income tax differences attributable to repair costs and certain other property-related costs for federal tax purposes. For these temporary tax differences, PG&E Corporation and the Utility recognize the deferred tax impact in the current period and record offsetting regulatory assets and liabilities. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates. The 2018 amount also reflects the impact of the amortization of excess deferred tax benefits to be refunded to customers as a result of the Tax Act passed in December of 2017.
[(3)] These amounts primarily represent the impact of income taxes related to share-based compensation adjustments associated with ASU 2016-09, Compensation - Stock Compensation (Topic 718): Improvements to Employee Share-Based Payment Accounting.

Utility Revenues and Costs that did not Impact Earnings

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

Cost of Electricity

The Utility's cost of electricity includes the cost 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 in Item 1.) The Utility's total purchased power is driven by customer demand, the availability of the Utility's own generation facilities (including Diablo Canyon and its hydroelectric plants), and the cost-effectiveness of each source of electricity.

| | Three Months Ended March 31, | |
|---|---|---|
| (in millions) | 2018 | 2017 |
| Cost of purchased power | $753 | $784 |
| Fuel used in own generation facilities | 66 | 63 |
| Total cost of electricity | $819 | $847 |
| Average cost of purchased power per kWh [1] | $0.123 | $0.108 |
| Total purchased power (in millions of kWh) [2] | 6,110 | 7,291 |

[1] Average cost of purchased power was impacted primarily by lower Utility electric customer demand, driven by customer departures to CCAs or direct access providers, and a larger percentage of higher cost renewable energy resources being allocated to the fewer remaining Utility electric customers. See further discussion in "Legislative and Regulatory Initiatives - Power Charge Indifference Adjustment OIR", below.
[2] The decrease in purchased power for the three months ended March 31, 2018 compared to the same period in 2017 was primarily due to lower Utility electric customer demand.

Cost of Natural Gas

The Utility's cost of natural gas includes the costs of procurement, storage and 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 in Item 1.) 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) | 2018 | 2017 |
| Cost of natural gas sold | $257 | $293 |
| Transportation cost of natural gas sold | 32 | 32 |
| Total cost of natural gas | $289 | $325 |
| Average cost per Mcf [1] of natural gas sold | $3.03 | $3.15 |
| Total natural gas sold (in millions of Mcf) | 85 | 93 |

[1] One thousand cubic feet

Operating and Maintenance Expenses

The Utility's operating expenses that did not impact earnings include certain costs that the Utility is authorized to recover as incurred such as pension contributions and public purpose programs costs. If the Utility were to spend more than authorized amounts, these expenses could have an impact to earnings.

Other Income, Net

The Utility's other income, net that did not impact earnings includes pension and other post-retirement benefit costs that fluctuate primarily from market and interest rate changes.

LIQUIDITY AND FINANCIAL RESOURCES

Overview

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

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

PG&E Corporation’s and the Utility’s credit ratings may be affected by the ultimate outcome of pending enforcement and litigation matters, including the outcome of the uncertainties and potential liabilities associated with the Northern California wildfires. Credit rating downgrades may increase the cost and availability of short-term borrowing, including commercial paper, the costs associated with credit facilities, and long-term debt costs. In addition, some of the Utility’s commodity contracts contain collateral posting provisions tied to the Utility’s credit rating from each of the major credit rating agencies. During the first quarter of 2018, Fitch Ratings, Standard & Poor’s Global Ratings, and Moody's Investors Service, Inc. downgraded PG&E Corporation's and the Utility’s credit ratings. At March 31, 2018, PG&E Corporation's and the Utility's credit ratings remained at investment grade levels. If the Utility’s credit rating were to fall below investment grade, the Utility estimates it would be required to fully collateralize up to $800 million in net liability positions. (See Note 7 and Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

PG&E Corporation's and the Utility's equity needs could increase materially and its liquidity and cash flows could be materially affected by potential costs and other liabilities in connection with the Northern California wildfires. The Utility’s equity needs will continue to be affected by the timing and amount of disallowed capital expenditures, and by fines, penalties and claims that may be imposed in connection with the matters described in Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1, "Part II. Other Information, Item 1. Legal Proceedings," and in the 2017 Form 10-K. In addition, PG&E Corporation’s and the Utility’s ability to access the capital markets in a manner consistent with its past practices, if at all, could be adversely affected by such matters. (See “Item 1A. Risk Factors” in the 2017 Form 10-K and in Part II below under “Item 1A. Risk Factors”.)

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.

Financial Resources

Debt and Equity Financings

There were no issuances under the PG&E Corporation February 2017 equity distribution agreement for the three months ended March 31, 2018. As of March 31, 2018, the remaining gross sales available under this agreement were $246.3 million.

PG&E Corporation issued common stock under the PG&E Corporation 401(k) plan and share-based compensation plans. During the three months ended March 31, 2018, 1.2 million shares were issued for cash proceeds of $35.1 million under these plans. The proceeds from these sales were used for general corporate purposes.

In January 2018, the Utility sent a notice of redemption to redeem all $400 million aggregate principal amount of the 8.25% Senior Notes due October 15, 2018. On January 31, 2018, the Utility deposited with the trustee funds sufficient to effect the early redemption of these bonds and satisfy and discharge its remaining obligation of $400 million on February 18, 2018.

In February 2018, the Utility's $250 million floating rate unsecured term loan, issued in February 2017, matured and was repaid. Additionally, in February 2018, the Utility entered into a $250 million floating rate unsecured term loan that will mature on February 22, 2019. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

In April 2018, PG&E Corporation entered into a $350 million floating rate unsecured term loan. The term loan matures on April 16, 2020, unless extended by PG&E Corporation pursuant to the terms of the term loan agreement. The proceeds were used for general corporate purposes, including the early redemption of PG&E Corporation's outstanding $350 million principal amount of 2.40% Senior Notes due March 1, 2019. On April 16, 2018, PG&E Corporation issued a notice of early redemption of these bonds, with a redemption date of April 26, 2018.

Revolving Credit Facilities and Commercial Paper Programs

At March 31, 2018, PG&E Corporation and the Utility had $179 million and $2.9 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 in Item 1.)

PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, respectively. For the three months ended March 31, 2018, PG&E Corporation and the Utility had an average outstanding commercial paper balance of $114 million and $31 million, and a maximum outstanding balance of $137 million and $205 million, respectively. At March 31, 2018, PG&E Corporation and the Utility had outstanding commercial paper balances of $121 million and $97 million, respectively.

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, 2018, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 49% and 48%, 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, 2018, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utility suspended quarterly cash dividends on both PG&E Corporation's and the Utility's common stock, beginning the fourth quarter of 2017, as well as the Utility's preferred stock, beginning the three-month period ending January 31, 2018, due to the uncertainty related to the causes of and potential liabilities associated with the Northern California wildfires. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

Utility Cash Flows

The Utility's cash flows were as follows:

| | Three Months Ended March 31, | |
|---|---|---|
| (in millions) | 2018 | 2017 |

| | | |
|---|---|---|
| Net cash provided by operating activities | $1,516 | $1,598 |
| Net cash used in investing activities | (1,475 ) | (1,235 ) |
| Net cash used in financing activities | (366 ) | (374 ) |
| Net change in cash and cash equivalents | $(325 ) | $(11 ) |

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, 2018, net cash provided by operating activities decreased by $82 million compared to the same period in 2017. This decrease was due to fluctuations in activities within the normal course of business such as the timing and amount of customer billings and collections and vendor billings and payments.

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

- the timing and amount of costs in connection with the Northern California wildfires, as well as potential liabilities in connection with third-party claims and fines or penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations;

- the timing and amounts of costs, including fines and penalties, that may be incurred in connection with the current and future enforcement, litigation, and regulatory matters, including the impact of the Butte fire and the timing and amount of related insurance recoveries, the safety culture OII, including other ratemaking tools that could be imposed by the CPUC as a result of phase two of the proceeding, the outcome of phase two of the ex parte OII, costs associated with potential recommendations that the third-party monitor may make related to the Utility’s conviction in the federal criminal trial, and potential penalties in connection with the Utility’s safety and other self-reports;

- the Tax Act, which is expected to accelerate the timing of federal tax payments and reduce revenue requirements, resulting in lower operating cash flows (see "Overview" above and "Regulatory Matters" below for more information);

- the timing and outcomes of the 2019 GT&S rate case, FERC TO18 and TO19 rate cases, 2018 CEMA filing, and other ratemaking and regulatory proceedings; and

- the timing of the resolution of the Chapter 11 disputed claims and the amount of principal and interest on these claims that the Utility will be required to pay.

Investing Activities

Net cash used in investing activities increased by $240 million during the three months ended March 31, 2018 as compared to the same period in 2017 primarily due to an increase in capital expenditures of approximately $250 million. The Utility’s investing activities primarily consist of construction of new and replacement facilities necessary to provide safe and reliable electricity and natural gas services to its customers. Cash used in investing activities also includes the proceeds from sales of nuclear decommissioning trust investments which are largely offset by the amount of cash used to purchase new nuclear decommissioning trust investments. The funds in the decommissioning trusts, along with accumulated earnings, are used exclusively for decommissioning and dismantling the Utility’s nuclear generation facilities.

The Utility's capital expenditures were approximately $5.7 billion in 2017. 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 $6.3 billion in capital expenditures in 2018, and $6.0 billion in 2019.

Financing Activities

Net cash used in financing activities decreased by $8 million during the three months ended March 31, 2018 as compared to the same period in 2017. This decrease was primarily due to the suspension of dividend payments (see "Dividends" section above), partially offset by an increase in net repayments of short-term and long-term borrowings.

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 of the Notes to the Condensed Consolidated Financial Statements in Item 1. The outcome of these matters, individually or in the aggregate, could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. In addition, PG&E Corporation and the Utility are involved in other enforcement and litigation matters described in the 2017 Form 10-K and "Part II. Other Information, Item 1. Legal Proceedings."

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC and other federal and state regulatory agencies. The resolutions of these and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows. Significant regulatory developments that have occurred since the 2017 Form 10-K was filed with the SEC are discussed below.

2017 General Rate Case

On May 11, 2017, the CPUC issued a final decision in the Utility's 2017 GRC, which determined the annual amount of base revenues (or "revenue requirements") that the Utility is 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 final decision approved, with certain modifications, the settlement agreement that the Utility, the ORA, TURN, and 12 other intervening parties jointly submitted to the CPUC on August 3, 2016 (the "settlement agreement"). The final decision approved a revenue requirement increase of $88 million for 2017, with additional increases of $444 million in 2018 and $361 million in 2019, in line with the amounts proposed in the settlement agreement.

As required by the final decision, the Utility has submitted a variety of compliance filings, including a filing on June 12, 2017, which provides an accounting for the January 2017 $300 million expense reduction announcement and on July 10, 2017, providing an update of the cost effectiveness study for the SmartMeter™ Upgrade project. On February 8, 2018, the CPUC extended the statutory deadline for the 2017 GRC from February 8, 2018 to August 9, 2018, to allow for comments and CPUC action on the SmartMeter™ Upgrade cost effectiveness study, as well as the scope and schedule for an audit of expenditures under the Utility's electric distribution undergrounding program.

As a result of the Tax Act, on March 30, 2018, the Utility submitted to the CPUC a PFM of the CPUC's final decision in the 2017 GRC. The PFM, if adopted, would reduce revenue requirements by $267 million and $296 million for 2018 and 2019 respectively, and increase rate base by $199 million and $425 million for 2018 and 2019, respectively. The Utility has proposed to work with the CPUC staff to implement rate changes under a schedule that minimizes rate volatility, which could defer some rate impacts beyond 2018. The timing of rate changes will also have an impact on the Utility's financing needs. The Utility cannot predict the timing and outcome of this PFM.

For more information, see the 2017 Form 10-K.

2020 General Rate Case and RAMP Filing

On November 30, 2017, the Utility filed its first RAMP report with the CPUC in advance of its 2020 GRC filing. The RAMP is a new CPUC requirement directing each large investor-owned energy utility to submit a report describing how it assesses its risks and how it plans to mitigate and minimize such risks in advance of the utility's GRC application. The objective of this report is to inform the CPUC of the utility's top safety-related risks, risk assessment procedures, and proposed mitigations of those risks for 2020-2022.

On April 3, 2018, the SED released a report assessing the Utility's RAMP report. The SED report requested, among other items, an updated risk analysis regarding wildfire risk mitigation strategies in the Utility's 2020 GRC. A workshop on the report was held on April 17, 2018, and the parties will submit comments on May 10, 2018. The RAMP results will be incorporated in the Utility’s 2020 GRC.

The Utility expects to file the 2020 GRC by September 1, 2018.

2015 Gas Transmission and Storage Rate Case

During 2016, the CPUC issued final decisions in phases one and two of the Utility’s 2015 GT&S rate case. The phase one decision adopted the revenue requirements that the Utility is authorized to collect through rates beginning August 1, 2016, to recover its costs of gas transmission and storage services for the 2015 GT&S rate case period (2015 through 2018). The phase two decision determined the allocation of the $850 million penalty assessed in the San Bruno Penalty Decision and the revenue requirement reduction for the five-month delay caused by the Utility’s violation of the CPUC ex parte communication rules in this proceeding.

The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The Utility would be required to take a charge in the future if the CPUC’s audit of 2011 through 2014 capital spending resulted in additional permanent disallowance. The decision established new one-way balancing accounts to track certain costs as well as various cost caps that will increase the risk of disallowance over the current rate case cycle.

As a result of the Tax Act, on March 30, 2018, the Utility submitted to the CPUC a PFM of the CPUC's final decision in the 2015 GT&S rate case. The PFM, if adopted, would reduce revenue requirements by $58 million and increase rate base by $12 million for 2018 (excluding the impact of an approximately $9 million increase in revenue requirement and a $60 million increase in rate base associated with the Utility's private letter ruling advice letter that is currently pending). The Utility has proposed to work with the CPUC staff to implement rate changes under a schedule that minimizes rate volatility, which could defer some rate impacts beyond 2018. The timing of rate changes will also have an impact on the Utility's financing needs. The Utility cannot predict the timing and outcome of this PFM.

In August 2016 and January 2017, TURN, ORA and Indicated Shippers filed applications for rehearing of the phase one and phase two decisions. The Utility cannot predict when or if the CPUC will grant the rehearings or if it will adopt the parties’ recommendations. Additionally, in June 2017, the Utility filed a PFM of the phase one decision to eliminate the requirement that the Utility install new cathodic protection systems in 2018 because the Utility is not in a position to identify the optimal location for such new systems in 2018. Instead, the Utility requested to be allowed to continue its current cathodic protection program. On April 26, 2018, the CPUC issued a final decision granting the Utility's PFM.

For more information, see the 2017 Form 10-K.

2019 Gas Transmission and Storage Rate Case

On November 17, 2017, the Utility filed its 2019 GT&S rate case application with the CPUC, covering the years 2019 through 2021. While the Utility has not formally proposed a fourth year for this rate case, it provided a revenue requirement and rates for 2022, in the event the CPUC adopts an additional year.

In its application, the Utility requested that the CPUC authorize a 2019 revenue requirement of $1.59 billion to recover anticipated costs of providing natural gas transmission and storage services beginning on January 1, 2019. This corresponds to an increase of $289 million over the Utility’s 2018 authorized revenue requirement of $1.30 billion. The Utility’s request also includes proposed revenue requirements of $1.73 billion for 2020, $1.91 billion for 2021, and $1.91 billion for 2022 if the CPUC orders a fourth year for the rate case period.

The requested rate base for 2019 is $4.66 billion, which corresponds to an increase of $0.95 billion over the 2018 authorized rate base of $3.71 billion. These rate base amounts exclude approximately $576 million of capital spending subject to audit by the CPUC related to 2011 through 2014 expenditures in excess of amounts adopted in the 2011 GT&S rate case. The Utility is unable to predict whether the $576 million, or a portion thereof, will ultimately be authorized by the CPUC and included in the Utility's future rate base. The Utility's request also excludes rate base adjustments that the Utility requested with the CPUC on November 14, 2017, resulting from the Internal Revenue Service's October 5, 2017 private letter ruling issued in connection with the CPUC's final phase two decision in the 2015 GT&S rate case. The Utility's request is based on capital expenditure forecasts of $971 million for 2019, $963 million for 2020, and $804 million for 2021 (which exclude common capital allocations).

The increase in revenue requirement is largely attributable to increased infrastructure investment and costs related to new natural gas storage safety and environmental regulations. Such new regulations were issued by: (1) DOGGR, which issued emergency safety and reliability natural gas storage measures in 2016 in response to the 2015 Southern California natural gas storage leak in Aliso Canyon. The final rule-making on new gas storage safety rules is expected in 2018; (2) the Pipeline and Hazardous Materials Safety Administration, which issued interim final rules, effective January 18, 2017, that address pipeline safety issues and mandate certain reporting requirements for operators of underground natural gas storage facilities; and (3) the CPUC, which issued General Order 112-F that became effective on January 1, 2017, and requires additional expenditures in the areas of gas leak repair, leak survey, and high consequence area identification, among other things. In its application, the Utility proposes a new two-way gas storage balancing account to address uncertainty around the anticipated DOGGR regulations, and also proposes a new memorandum account to track costs related to other anticipated new regulations.

As a result of the existing and anticipated gas storage safety requirements, the Utility developed and proposed in its 2019 GT&S rate case application a natural gas storage strategy which includes the discontinuation (through closure or sale) of operations at two gas storage fields. The discontinuation is expected to reduce long-term costs for customers and to reduce safety and environmental risks.

As a result of the Tax Act, on March 30, 2018, the Utility submitted updated testimony to the CPUC. The updated testimony, including the pending private letter ruling advice letter, reduces the Utility's previously forecasted revenue requirement by $25 million for 2019, $30 million for 2020, $22 million for 2021, and $5 million for 2022, and increases rate base by $188 million for 2019, $254 million for 2020, $378 million for 2021, and $469 million for 2022. The Utility cannot predict the timing and outcome of this submittal.

On April 24, 2018, the CPUC issued a scoping memo and ruling establishing a procedural schedule. Testimony is scheduled to be served in the second and third quarter of 2018, and evidentiary hearings are scheduled to begin in the third quarter of 2018.

For more information, see the 2017 Form 10-K.

Transmission Owner Rate Cases

Transmission Owner Rate Case for 2017 (the "TO18" rate case)

On July 29, 2016, the Utility filed its TO18 rate case at the FERC requesting a 2017 retail electric transmission revenue requirement of $1.72 billion, a $387 million increase over the 2016 revenue requirement of $1.33 billion. The forecasted network transmission rate base for 2017 was $6.7 billion. The Utility is seeking a return on equity of 10.9%, which includes an incentive component of 50 basis points for the Utility’s continuing participation in the CAISO. In the filing, the Utility forecasted that it would make investments of $1.30 billion in 2017 in various capital projects.

On September 30, 2016, the FERC issued an order accepting the Utility’s July 2016 filing and set it for hearing, but held the hearing procedures in abeyance for settlement procedures. The order set an effective date for rates of March 1, 2017, and made the rates subject to refund following resolution of the case. On March 17, 2017, the FERC issued an order terminating the settlement procedures due to an impasse in the settlement negotiations reported by the parties.

Hearings were held from January 9, 2018 through January 30, 2018. During the hearings, the Utility, intervenors, and the FERC trial staff, addressed questions relating to return on equity, capital structure, depreciation rates, capital additions, rate base, operating and maintenance expense, administrative and general expense, and the allocation of common, general and intangible costs. On April 11, 2018, the FERC extended the initial decision deadline from June 1, 2018, to October 1, 2018.

Also, on March 31, 2017, several of the parties that had already intervened in the TO18 rate case filed a complaint at the FERC, and requested that the complaint be consolidated with the rate case. The complaint asserts that the Utility's revenue requirement request in TO18 is unreasonably high and should be reduced. The complaint asks that, if the outcome of the litigation in TO18 is that the Utility's revenue requirement should be set at a lower level than the revenue requirement from the TO17 settlement, that the FERC order refunds to that lower level determined in TO18 litigation. On April 20, 2017, the Utility answered the complaint, requesting that FERC dismiss it. On November 16, 2017, FERC dismissed the complaint as the Utility had requested. On December 18, 2017, the complainants filed a request for rehearing of that order, and on January 16, 2018, FERC issued an order granting rehearing for further consideration. That order does not address the merits of the complaint; it simply gives FERC more time to reconsider its prior order dismissing the complaint. The Utility is unable to predict when FERC may issue an order on the merits of the complaint.

Transmission Owner Rate Case for 2018 (the "TO19" rate case)

On July 27, 2017, the Utility filed its TO19 rate case at the FERC requesting a 2018 retail electric transmission revenue requirement of $1.79 billion, a $74 million increase over the proposed 2017 revenue requirement of $1.72 billion. The forecasted network transmission rate base for 2018 is $6.9 billion. The Utility is seeking an ROE of 10.75%, which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAISO. In the filing, the Utility forecasted capital expenditures of approximately $1.4 billion. On September 28, 2017, the FERC issued an order accepting the Utility's July 2017 filing, subject to hearing and refund, and established March 1, 2018, as the effective date for rate changes. FERC also ordered that the hearings be held in abeyance pending settlement discussion among the parties. The next settlement conference is scheduled for May 16, 2018.

In response to a FERC order, on May 14, 2018, the Utility will file a proposal to reflect the impact of the Tax Act on its TO tariff rates effective, March 1, 2018, in the resolution of the TO19 rate case. The Utility cannot predict the timing and outcome of FERC's response.

On September 29, 2017, several of the parties that have intervened in the TO18 rate case filed a complaint at the FERC, and requested that the complaint be consolidated with the TO19 rate case. The TO19 complaint asserts that the Utility's revenue requirement request in TO19 is unreasonably high and should be reduced. The complaint asks that, if the outcome of the litigation in TO19 is that the Utility's revenue requirement should be set at a lower level than the settled revenue requirement approved by FERC in TO18, FERC order refunds to that lower level determined in the TO19 litigation. On October 17, 2017, the Utility answered the complaint, requesting that FERC dismiss it. The Utility is unable to predict when and how the FERC will respond to the complaint.

Transmission Owner Rate Cases for 2015 and 2016 (the "TO16" and "TO17" rate cases, respectively)

On January 8, 2018, the Ninth Circuit Court of Appeals issued an opinion granting an appeal of FERC's decisions in the TO16 and TO17 rate cases to grant the Utility a 50 basis point ROE incentive adder for its continued participation in the CAISO. Those decisions have been remanded to FERC for further proceedings consistent with the Court of Appeals' opinion. If FERC concludes on remand that the Utility is no longer authorized to receive the 50 basis point ROE incentive adder, the Utility would incur a refund obligation of $1 million and $8.5 million for TO16 and TO17, respectively. Alternatively, if FERC again concludes that the Utility should receive the 50 basis point ROE incentive adder and provides the additional explanation that the Ninth Circuit found the FERC's prior decisions lacked, then the Utility would not owe any refunds for this issue for TO16 or TO17.

On February 28, 2018, the Utility filed a motion to establish procedures on remand requesting a paper hearing and additional briefing on the issues identified in the Ninth Circuit Court's opinion. The Utility is unable to predict the timing and outcome of FERC's response to this motion.

For more information, see the 2017 Form 10-K.

Diablo Canyon Nuclear Power Plant

Joint Proposal for Plant Retirement

On August 11, 2016, the Utility submitted an application to the CPUC to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a portfolio of energy efficiency and GHG-free resources. The application implements a joint proposal between the Utility and the Friends of the Earth, Natural Resources Defense Council, Environment California, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, and Alliance for Nuclear Responsibility (together, the "Joint Parties").

On January 11, 2018, the CPUC issued a final decision in the Utility's proposal to retire Diablo Canyon Unit 1 by 2024 and Unit 2 by 2025. The CPUC also:

- deferred consideration of replacement resources to the CPUC's Integrated Resource Planning proceeding;
- authorized rate recovery for up to $211.3 million (compared with the $352.1 million requested by the Utility) for an employee retention program;

- authorized rate recovery for an employee retraining program of $11.3 million requested by the Utility;
- rejected rate recovery of the proposed $85 million for the community impacts mitigation program on the ground that rate recovery for such a program requires legislative authorization;
- authorized rate recovery of $18.6 million of the total Diablo Canyon license renewal cost of $53 million and rate recovery of cancelled project costs equal to 100% of direct costs incurred prior to June 30, 2016, and 25% of direct costs incurred after June 30, 2016, based on a settlement agreement among the Utility, the Joint Parties, and certain other parties that the Utility filed with the CPUC in May 2017; and
- approved the amortization of the book value for Diablo Canyon consistent with the Diablo Canyon closure schedule.

On March 7, 2018, the Utility submitted a request to the NRC to withdraw its Diablo Canyon license renewal application.

On March 16, 2018, California legislative leaders announced they are moving forward with legislation in the California Assembly to meet the key remaining goals of the Diablo Canyon joint proposal agreement. The bill, Senate Bill 1090, seeks to:

- require the CPUC to approve the community impact mitigation settlement of $85 million, originally proposed in the joint settlement agreement;
- direct the CPUC to manage its Integrated Resource Planning to ensure that there is no increase in GHG emissions as a result of the Diablo Canyon retirement; and
- require the CPUC to approve full funding of the $352.1 million Diablo Canyon employee retention program, originally proposed in the joint settlement agreement.

California State Lands Commission Lands Lease

On June 28, 2016, the California State Lands Commission approved a new lands lease for the intake and discharge structures at Diablo Canyon to run concurrently with Diablo Canyon’s current operating licenses, until Diablo Canyon Unit 2 ceases operations in August 2025. The Utility believes that the approval of the new lease will ensure sufficient time for the Utility to identify and bring online a portfolio of GHG-free replacement resources. The Utility will submit a future lease extension request to address the period of time required for plant decommissioning, which under NRC regulations can take as long as 60 years. On August 28, 2016, the World Business Academy filed a writ in the Los Angeles Superior Court asserting that the State Lands Commission committed legal error when it determined that the short term lease extension for an existing facility was exempt from review under the California Environmental Quality Act and alleging that the State Lands Commission should be required to perform an environmental review of the new lands lease. The trial took place on July 11, 2017, in Los Angeles Superior Court and the judge dismissed the petition on all grounds, ruling that the State Lands Commission properly determined the short term lease extension was subject to the existing facilities exemption under the California Environmental Quality Act. The World Business Academy appealed this decision and the matter is currently before the California Court of Appeals in Los Angeles, Second District. The trial date has not been set. The Utility is unable to predict the timing and outcome of this proceeding.

Asset Retirement Obligations

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

While the current NDCTP forecast includes employee severance program estimates, it does not include estimated costs related to the final decision’s employee retention and retraining and development programs, and the San Luis Obispo County community mitigation program; the employee retraining program costs will be included in future cost estimates. The Utility intends to conduct a site-specific decommissioning study to update the 2015 NDCTP forecast and to submit the study to the CPUC by mid-2019.

The Utility expects to file its 2018 NDCTP application in late 2018 or early 2019. For more information, see "Asset Retirement Obligations" in Note 2 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 Form 10-K.

Application to Establish a Wildfire Expense Memorandum Account

On July 26, 2017, the Utility filed an application with the CPUC requesting to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of wildfire costs in excess of insurance at a future date. Concurrently with this application, the Utility also submitted a motion to the CPUC requesting that the WEMA be deemed effective as of July 26, 2017, such that the Utility may begin recording costs to the account while the application is pending before the CPUC.

Under the WEMA as proposed, the Utility would record costs related to wildfires, including: (1) payments to satisfy wildfire claims, including any deductibles, co-insurance and other insurance expense paid by the Utility but excluding costs that have already been authorized in the Utility’s GRC; (2) outside legal costs incurred in the defense of wildfire claims; (3) insurance premium costs not in rates; and (4) the cost of financing these amounts. Insurance proceeds, as well as any payments received from third parties, would be credited to the WEMA as they are received. The WEMA would not include the Utility’s costs for fire response and infrastructure costs which are tracked in CEMA. The Utility would be required to file an application to seek approval to recover costs tracked in WEMA.

A prehearing conference was held on December 8, 2017, and a scoping memo was issued on January 11, 2018. The Utility filed its opening brief with the CPUC on January 25, 2018, and other parties’ briefs were filed on February 15, 2018. On February 22, 2018, the Utility filed its reply brief. The Utility cannot predict the timing and outcome of this proceeding.

Catastrophic Event Memorandum Account Applications

The CPUC allows utilities to recover the reasonable, incremental costs of responding to catastrophic events through a CEMA. The CEMA tariff authorizes the utilities to recover costs incurred in connection with a catastrophic event that has been declared a disaster or state of emergency by competent federal or state authorities. In 2014, the CPUC directed the Utility to perform additional fire prevention and vegetation management work in response to the severe drought in California. The costs associated with this work were tracked in the CEMA. While the Utility believes such costs are recoverable through CEMA, its CEMA applications are subject to CPUC approval.

2016 CEMA Application

In 2016, the Utility submitted a request to the CPUC to authorize recovery under the CEMA tariff revenue requirement of approximately $146 million for recorded capital and expense costs related to the 2015 drought mitigations and emergency response activities for declared disasters that occurred from December 2012 through March 2016. On January 4, 2018, ORA, TURN, and the Utility filed an all-party motion with the CPUC seeking approval of a settlement agreement these parties have entered into. The settlement agreement proposes that the Utility’s total CEMA revenue requirement request be reduced by $29 million, from $146 million to $117 million.

2018 CEMA Application

On March 30, 2018, the Utility submitted to the CPUC its 2018 CEMA application requesting cost recovery of $183 million in connection with nine catastrophic events that included fire and storm declared emergencies from the middle of 2016 through early 2017, and $405 million for work to cut back or remove dead or dying trees in 2016 and 2017 resulting from years of drought conditions and associated bark beetle infestation. The 2018 CEMA application also seeks cost recovery of $555 million on a forecast basis for additional tree mortality and fire mitigation work anticipated in 2018 and 2019.

In the application, the Utility proposed to recover the authorized CEMA expenses and capital costs that have already been incurred over a two-year period beginning on January 1, 2019, or as soon as possible thereafter. With respect to the Utility's forecasted expenses for 2018 and 2019, the Utility proposed to recover the 2018 and 2019 revenue requirements over a two-year period beginning on January 1, 2019. The 2018 CEMA application does not include costs related to Butte fire or the October 2017 Northern California wildfires. The Utility has requested a decision by the end of 2018.

PG&E Corporation and the Utility are unable to predict the outcomes of these proceedings.

Other Regulatory Proceedings

Transportation Electrification

California Law (Senate Bill 350) requires the CPUC, in consultation with the California Air Resources Board and the CEC, to direct electrical corporations to file applications for programs and investments to accelerate widespread TE. In September 2016, the CPUC directed the Utility and the other large IOUs to file TE applications which include both short-term projects (of up to $20 million in total) and two- to five-year programs with a requested revenue requirement determined by the Utility.

On January 20, 2017, the Utility filed its TE application with the CPUC requesting a total of up to $253 million (approximately $211 million in capital expenditures) in program funding over five years (2018-2022) related to make-ready infrastructure for TE in medium to heavy-duty vehicle sectors, fast charging stations, and short-term projects which includes a series of TE demonstration projects and pilot programs. On January 11, 2018, the CPUC approved, with modifications, four out of the five short-term projects proposed by the Utility for a total of approximately $8 million.

On March 30, 2018, the CPUC issued a proposed decision approving, with modifications, the Utility’s standard review program proposals for approximately $238 million ($198 million of capital expenditures) to support make-ready infrastructure supporting public fast charging and medium to heavy-duty fleets. In the FleetReady program, the Utility will have a goal of providing utility-owned make-ready infrastructure at 700 sites, conducting operation and maintenance of installed infrastructure, and educating customers on the benefits of electric vehicles. The proposed decision would give customers the option of owning the make-ready infrastructure installed beyond the customer meter in lieu of utility ownership. The Fast Charge program will have a goal to install make-ready infrastructure at 52 public charging sites, increase access to charging stations for customers, and reduce driver range anxiety. The costs associated with the standard review projects will be tracked in a one-way balancing account. The CPUC is expected to issue a final decision in the second quarter of 2018.

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 DERs. The Utility’s proposal is designed to allow energy technologies to be integrated into the larger grid while continuing to provide customers with safe, reliable, and affordable electric service.

The CPUC issued a final decision on February 15, 2018, requiring the California IOUs to use the CEC’s DER forecast for the 2018-2019 distribution planning cycle. The decision also requires the IOUs to develop an alternative planning forecast scenario in 2018 to establish a method for calculating costs and benefits for DER grid integration to better inform DER sourcing policies. The Utility has historically used the CEC forecast for planning and will have the opportunity to adjust forecasts for EV, photovoltaic, and energy storage, if needed during the planning cycle.

The CPUC's final decision also required the Utility to develop an annual grid needs assessment and an annual distribution deferral opportunity report, to identify proposed electric distribution investments that potentially could be deferred by deployment of DERs. The decision also extends to all DER distribution deferral projects the regulatory incentive mechanism being piloted in the Integrated Distributed Energy Resources Proceeding where the Utility can earn a 4% pre-tax incentive on the annual payments for DER deferral contracts.

On March 26, 2018, the CPUC issued a final decision requiring the Utility to include a grid modernization plan addressing distribution system upgrades required to deploy DERs in the Utility's GRC. The grid modernization plan must include a narrative 10-year vision for investments needed to support DER growth, safety, and reliability, and a status update of previously funded DER-related grid modernization GRC projects. The Utility is required to submit a grid modernization plan with each GRC application starting with its 2020 GRC application.

Integrated Distributed Energy Resources Proceeding

On April 4, 2016, the CPUC issued a ruling proposing to establish, on a pilot basis, an interim program offering regulatory incentives to the California IOUs for the deployment of cost-effective DERs. The ruling stated that it did not intend for this phase to adopt a new regulatory framework or business model for the California electric utilities. On December 22, 2016, the CPUC issued a final decision in the proceeding which authorizes a pilot to test a regulatory incentive mechanism through which the Utility will earn a 4% pre-tax incentive on annual payments for DERs, as well as test a regulatory process that will allow the Utility to competitively solicit DER services to defer electric distribution infrastructure. Each IOU is required to conduct at least one pilot, but may conduct up to three additional pilots.

In June 2017, the Utility submitted a pilot project proposal to the CPUC for approval to begin solicitations. The pilot aims to evaluate the effectiveness of an earnings opportunity in motivating utilities to source DERs. In December 2017, the CPUC granted the Utility’s request to cancel the current pilot project proposal due to the damage of the Utility’s facilities in the area of the Northern California wildfires.

On February 12, 2018, the CPUC issued an amended scoping memo and ruling to investigate DER sourcing mechanisms beyond the existing competitive solicitations for DERs. The scope now includes: (1) the design, for CPUC consideration and adoption, of alternative sourcing mechanisms or approaches that satisfy distribution planning objectives; and (2) the consideration of how existing programs, incentives, and tariffs can be coordinated to maximize locational benefits and minimize DER costs. The IOUs and other parties filed opening and reply comments on March 29, 2018, and April 13, 2018, respectively, in response to the CPUC's ruling to further investigate sourcing mechanisms beyond the existing competitive solicitations framework.

LEGISLATIVE AND REGULATORY INITIATIVES

Power Charge Indifference Adjustment OIR

On April 25, 2017, the Utility, along with Southern California Edison Company and San Diego Gas & Electric Company, filed a joint application with the CPUC regarding allocating costs associated with long-term power commitments in a manner that treats all customers equally. At issue is how customers within communities that choose to implement CCA power arrangements and those served under direct access pay for their share of the costs. The utilities believe that these CCA and direct access customers are not paying their full share of costs associated with the long-term commitments, which results in other customers paying more, which is inconsistent with state law. The Utility projects that more than half of its customers will purchase electricity from a CCA or direct access provider by 2020. Without changes to the current cost allocation system, a portion of the contract and facilities costs will be shifted to customers who remain with the Utility or live in areas that do not have access to alternative electricity providers. The utilities’ joint proposed approach would replace the current system, which is known as the PCIA, with an updated system known as the Portfolio Allocation Methodology.

On June 29, 2017, the CPUC dismissed the Utility’s joint Portfolio Allocation Methodology application without prejudice and instead approved an OIR to review, revise, and consider alternatives to the PCIA. The OIR will focus on PCIA within the larger context of consumer choice in energy services. On September 25, 2017, the CPUC issued a scoping memo and ruling establishing a procedural schedule and a new overall goal to mitigate cost increases for both bundled and CCA and direct access customers. On April 2, 2018, the Utility served joint testimony with Southern California Edison and San Diego Gas & Electric to the CPUC along with eight other parties including ORA, TURN, and California Community Choice Association. The Utility, Southern California Edison, and San Diego Gas & Electric served joint rebuttal testimony on April 23, 2018. Evidentiary hearings are scheduled to begin on May 7, 2018, and a proposed decision is expected in the third quarter of 2018.

OIR to Consider Strategies and Guidance for Climate Change Adaptation

On April 26, 2018, the CPUC opened an OIR to consider strategies for integrating climate change adaptation considerations into relevant CPUC proceedings. Phase one of the OIR will broadly consider how to integrate climate change adaptation into the investor-owned electric and gas utilities' existing planning and operations to ensure their safety and reliability.

The CPUC will consider (1) the definition of climate adaptation that should be used for IOUs, (2) resources that should be used to inform CPUC proceedings and utility planning and operations, (3) climate parameters that should be used to determine climate-driven risks and resilience for electric and natural gas utilities, (4) climate scenarios, climate-relevant parameters, and resilience metrics that should be used in electric and gas utility planning and operations, and in CPUC proceedings, to address climate adaptation in a consistent manner, and (5) climate impacts specifically relevant to disadvantaged communities.

According to the OIR, the scope of the proceeding may further include consideration of robust utility-conducted vulnerability assessments, and the scope and breadth of those assessments. Guidance resulting from this OIR will instruct utilities on how to incorporate adaptation in their investment plans, program design, and operations. The scope for future phases of this proceeding will be considered at a later time, but they are anticipated to consider climate adaptation for CPUC-regulated water and telecommunications utilities.

While the preliminary schedule for phase one is subject to change, comments are due in late May 2018, followed by workshops expected in late summer 2018. The CPUC anticipates issuing a proposed decision by late April 2019.

ENVIRONMENTAL MATTERS

The Utility's operations are subject to extensive federal, state, and local laws and permits relating to the protection of the environment and the safety and health of the Utility's personnel and the public. These laws and requirements relate to a broad range of the Utility's activities, including the remediation of hazardous wastes; the reporting and reduction of carbon dioxide and other GHG emissions; the discharge of pollutants into the air, water, and soil; the reporting of safety and reliability measures for natural gas storage facilities; and the transportation, handling, storage, and disposal of spent nuclear fuel. (See Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 of this Form 10-Q, as well as "Item 1A. Risk Factors" and Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 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 in Item 1). 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 MD&A "Contractual Commitments" in Item 7 of the 2017 Form 10-K.

Off-Balance Sheet Arrangements

PG&E Corporation and the Utility do not have any off-balance sheet arrangements that have had, or are reasonably likely to have, a current or future material effect on their financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures, or capital resources, other than those discussed in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 of the 2017 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 risks associated with adverse changes in commodity prices, interest rates, and counterparty credit.

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 risk mitigation purposes 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 are discussed in detail in the 2017 Form 10-K. There were no significant developments to the Utility's and PG&E Corporation's risk management activities during the three months ended March 31, 2018.

## 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, AROs, and pension and other post-retirement 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 2017 Form 10-K.

## ACCOUNTING STANDARDS ISSUED BUT NOT YET ADOPTED

See the discussion above in Note 2 of the Notes to the Condensed Consolidated Financial Statements in Item 1.

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 that 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 impact of the Northern California wildfires, including whether the Utility will be able to recover costs for service restoration and repair to the Utility's facilities through CEMA ; the timing and outcome of the wildfire investigations, including into the causes of the wildfires; whether the Utility may have liability associated with these fires; if liable for one or more fires, whether the Utility would be able to recover all or part of such costs through insurance or through regulatory mechanisms, to the extent insurance is not available or exhausted; and potential liabilities in connection with fines or penalties that could be imposed on the Utility if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations;

- the timing and outcome of the Butte fire litigation, the timing and outcome of any proceeding to recover from customers restoration and repair costs and costs in excess of insurance, if any; the effect, if any, that the SED’s $8.3 million citations issued in connection with the Butte fire may have on the Butte fire litigation; and whether additional investigations and proceedings in connection with the Butte fire will be opened and any additional fines or penalties imposed on the Utility;

- whether the CPUC approves the Utility’s application to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of wildfire costs in excess of insurance at a future date, and the outcome of any potential request to recover such costs;

- the impact of the Tax Act, and the timing and outcome of CPUC decision(s) related to the Utility’s March 30, 2018 submissions in connection with the impact of the Tax Act on the Utility’s rate cases and its implementation plan;

- the timing and outcomes of the 2019 GT&S rate case, TO18 and TO19 rate cases, 2018 CEMA, and other ratemaking and regulatory proceedings;

- the cost of the Utility's community wildfire safety program, and the timing and outcome of any proceeding to recover such costs through rates;

- the outcome of the probation and the monitorship imposed by the federal court after the Utility’s conviction in the federal criminal trial in 2017, the timing and outcomes of the debarment proceeding, the SED’s unresolved enforcement matters relating to the Utility’s compliance with natural gas-related laws and regulations, and other investigations that have been or may be commenced relating to the Utility’s compliance with natural gas- and electric-related laws and regulations, ex parte communications, and the ultimate amount of fines, penalties, and remedial costs that the Utility may incur in connection with the outcomes;

- the timing and outcomes of investigations by the U.S. Attorney's Office in San Francisco and the California Attorney General's office related to communications between the Utility's personnel and CPUC officials, whether additional criminal or regulatory investigations or enforcement actions are commenced with respect to allegedly improper communications, and the extent to which such matters negatively affect the final decisions to be issued in the Utility's ratemaking proceedings;

- the effects on PG&E Corporation and the Utility's reputations caused by the Utility's conviction in the federal criminal trial in 2017, the CPUC's investigations of natural gas incidents, and the Northern California wildfires, 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, and timely recover its costs through rates; whether the Utility can continue implementing a streamlined organizational structure and achieve project savings, 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;

- whether the Utility and its third-party vendors and contractors are able to protect the Utility's operational networks and information technology systems from cyber- and physical attacks, or other internal or external hazards;

- the timing and outcome of the complaint filed by the CPUC and certain other parties with the FERC on February 2, 2017, that requests that the Utility provide an open and transparent planning process for its capital transmission projects that do not go through the CAISO's Transmission Planning Process to allow for greater participation and input from interested parties; and the timing and ultimate outcome of the Ninth Circuit Court of Appeals decision on January 8, 2018, to reverse FERC's decision granting PG&E a 50 basis point ROE incentive adder for continued participation in the CAISO and remanding the case to FERC for further proceedings;

- 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 safety culture OII, including its phase two proceeding opened on May 8, 2017, and future legislative or regulatory actions that may be taken, such as requiring the Utility to separate its electric and natural gas businesses, or restructure into separate entities, or undertake some other corporate restructuring, or implement corporate governance changes;

- the outcome of current and future self-reports, investigations, or other enforcement proceedings that could be commenced or notices of violation that could be issued 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, electric grid reliability, inspection and maintenance practices, customer billing and privacy, physical and cybersecurity, environmental laws and regulations; and the outcome of existing and future SED notices of violations;

- the impact of comments and CPUC action in connection with the Utility's SmartMeter™ Upgrade cost-benefit analysis;

- 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 impact of California Governor Jerry Brown's executive order issued on January 26, 2018, to implement a new target of five million zero-emission vehicles on the road in California by 2030;

- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility's natural gas compressor station site located near Hinkley, California and the Utility's fossil fuel-fired generation sites;

- 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 potential actions, such as legislation, taken by state agencies that may affect the Utility's ability to continue operating Diablo Canyon until its planned retirement; and whether the Utility will be able to successfully implement its retention and retraining and development programs for Diablo Canyon employees as a result of its planned retirement by 2024 and 2025;

- the impact of wildfires, droughts, floods, or other weather-related conditions or events, climate change, natural disasters, acts of terrorism, war, vandalism (including cyber-attacks), downed power lines, and other events, that can cause unplanned outages, reduce generating output, disrupt the Utility's service to customers, or damage or disrupt the facilities, operations, or information technology and systems owned by the Utility, its customers, or third parties on which the Utility relies, and the reparation and other costs that the Utility may incur in connection with such conditions or events; the impact of the adequacy of the Utility's emergency preparedness; whether the Utility incurs liability to third parties for property damage or personal injury caused by such events; 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 sufficient to cover the Utility's liability;

- the outcome of state initiatives and numerous bills introduced by state legislators to address climate resilience and augment disaster planning in response to the wildfires in California, that if passed, could affect the Utility's cost recovery mechanisms, operational requirements, and resiliency plans for certain catastrophic events;

- the breakdown or failure of equipment that can cause damages, including fires, and unplanned outages; and whether the Utility will be subject to investigations, penalties, and other costs in connection with such events;

- how the CPUC and the California Air Resources Board implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, DERs, EVs, 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, changing customer demand for natural gas and electric services, and an increasing number of customers departing the Utility's procurement service for CCAs;

- 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, as a result of Westinghouse's Chapter 11 proceeding and its bankruptcy court approved plan of reorganization, the Utility will experience issues with nuclear fuel supply, nuclear fuel inventory, and related services and products that Westinghouse supplies, and whether the implementation of the plan or reorganization will affect the Utility's contracts with Westinghouse;

- the amount and timing of charges reflecting probable liabilities for third-party claims; the extent to which costs incurred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

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

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changes in credit ratings which could, among other things, result in higher borrowing costs and fewer financing options, especially if PG&E Corporation or the Utility were to lose their investment grade credit ratings;

- the impact of 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 uncertainty in connection with the Northern California wildfires, the ultimate outcomes of the CPUC's pending investigations, and other enforcement matters will impact the Utility's ability to make distributions to PG&E Corporation, and whether they will continue impacting PG&E Corporation's and the Utility'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;

- changes in the regulatory and economic environment, including potential changes affecting renewable energy sources and associated tax credits, as a result of the current federal administration; 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.

Additional information about risks and uncertainties, including more detail about the factors described in this report, is included throughout MD&A, in “Item 1A. Risk Factors” below, and in the 2017 Form 10-K, including the “Risk Factors” section. Forward-looking statements speak only as of the date they are made. 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.

Additionally, PG&E Corporation and the Utility routinely provide links to the Utility’s principal regulatory proceedings before the CPUC and the FERC at http://investor.pgecorp.com, under the “Regulatory Filings” tab, so that such filings are available to investors upon filing with the relevant agency. It is possible that these regulatory filings or information included therein could be deemed to be material information. The information contained on this website is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC. PG&E Corporation and the Utility are providing the address to this website solely for the information of investors and do not intend the address to be an active link. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the “News & Events: Events & Presentations” tab, in order to publicly disseminate such information.

## 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 MD&A and in Note 7: Derivatives and Note 8: Fair Value Measurements of the Notes to the Condensed Consolidated Financial Statements in Item 1.)

## 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, 2018, PG&E Corporation’s and the Utility’s respective principal executive officers and principal financial officers have concluded that such controls and procedures are 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, as amended, is (i) recorded, processed, summarized, and reported within the time periods specified in the SEC rules and forms, and (ii) 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, 2018, 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 proceedings, PG&E Corporation and the Utility are parties to various lawsuits and regulatory proceedings in the ordinary course of their business. For more information regarding PG&E Corporation's and the Utility's contingencies, see Note 9 of the Notes to the Condensed Consolidated Financial Statements in Item 1 and Part I, MD&A: "Enforcement and Litigation Matters."

Order Instituting an Investigation into 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.

On May 8, 2017, the CPUC released the consultant’s report, accompanied by a scoping memo and ruling. The scoping memo establishes a second phase in this OII in which the CPUC will evaluate the safety recommendations of the consultant that may lead to the CPUC’s adoption of the recommendations in the report, in whole or in part. This phase of the proceeding will also consider all necessary measures, including, but not limited to, a potential reduction of the Utility’s return on equity until any recommendations adopted by the CPUC are implemented. On November 17, 2017, the CPUC issued a phase two scoping memo and procedural schedule. The scoping memo directed the Utility and other parties, including the Office of Safety Advocate, ORA, and TURN, to file testimony addressing a number of issues including adoption of the safety recommendations from the consultant, the Utility’s implementation process for the safety recommendations of the consultant, the Utility’s Board of Director’s actions and initiatives related to safety culture and the consultant’s recommendations, the Utility’s corrective action program, and the Utility’s response to certain specified safety incidents that occurred in 2013 through 2015. The Utility’s testimony was submitted to the CPUC on January 8, 2018, and stated that the Utility agrees with all of the recommendations of the consultant and supports their adoption by the CPUC.

On February 23, 2018, the Utility served its rebuttal testimony in response to the Office of the Safety Advocates', ORA's, and TURN's testimony served on February 16, 2018. Parties submitted joint comments to the CPUC on March 9, 2018, identifying areas of disputed facts and requesting more time to pursue a settlement. The parties were unable to reach a settlement. Evidentiary hearings took place on April 11, 2018, and addressed the CPUC's questions on a variety of topics including the consultant's report, safety (public, employee, and contractor), cyber security, wildfires, compensation, safety metrics, the Utility's Board of Directors, performance-based ratemaking, safety management systems, the Utility's safety and health plan, and the Utility's implementation plan. Opening briefs, in which parties are expected to propose the next steps of this proceeding, and reply briefs will be submitted by May 9, 2018, and May 23, 2018, respectively.

PG&E Corporation and the Utility are unable to predict the outcome of this proceeding, including whether additional fines, penalties, or other ratemaking tools will ultimately be adopted by the CPUC, and whether the CPUC will require that a portion of return on equity for the Utility be dependent on making safety progress as the CPUC may define in this proceeding.

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, the Utility, and the California Attorney General’s Office, see Part I, Item 3. "Legal Proceedings” in the 2017 Form 10-K.

ITEM 1A. RISK FACTORS

For information about the significant risks that could affect PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows, see the section of the 2017 Form 10-K entitled “Risk Factors,” as supplemented below, and the section of this quarterly report entitled “Forward-Looking Statements.”

PG&E Corporation’s and the Utility’s financial results will be affected by their ability to continue accessing the capital markets and by the terms of debt and equity financings.

PG&E Corporation and the Utility will continue to seek funds in the capital and credit markets to enable the Utility to make capital investments, and to pay fines that may be imposed in the future, as well as legal and regulatory costs. PG&E Corporation’s and the Utility’s ability to access the capital and credit markets and the costs and terms of available financing depend primarily on PG&E Corporation’s and the Utility’s credit ratings and outlook. Their credit ratings and outlook can be affected by many factors, including pending or anticipated litigation, the pending Cal Fire and CPUC investigations and CPUC ratemaking proceedings, substantial legislative or judicial changes to the application of inverse condemnation, and by the December 20, 2017 decision of the Boards of Directors of PG&E Corporation and the Utility to suspend dividends, as well as the perceived impact of all such matters on PG&E Corporation’s and the Utility’s financial condition, whether or not such perception is accurate. During the first quarter of 2018, Fitch Ratings, Standard & Poor’s Global Ratings, and Moody's Investor Services lowered PG&E Corporation's and the Utility’s credit ratings. If PG&E Corporation’s or the Utility’s credit ratings were to be further downgraded, in particular to below investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced, or lack of, access to the commercial paper market and additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need. Other factors can affect the availability and terms of debt and equity financing, including changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, an increase in interest rates by the Federal Reserve Bank, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about matters discussed under “Enforcement and Litigation Matters” in Part II, Item 1. Legal Proceedings and Note 9 of the Notes to the Condensed Consolidated Financial Statements in Part I, Item 1. The negative publicity and the uncertainty about the outcomes of these matters may undermine confidence in management’s ability to execute its business strategy and restore a constructive regulatory environment, which could adversely impact PG&E Corporation’s stock price. Further, the market price of PG&E Corporation common stock could decline materially depending on the outcome of these matters. The amount and timing of future share issuances also could affect the stock price.

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

During the quarter ended March 31, 2018, PG&E Corporation did not make any equity contributions to the Utility.

### Issuer Purchases of Equity Securities

During the quarter ended March 31, 2018, PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. PG&E Corporation does not have any preferred stock outstanding. During the quarter ended March 31, 2018, 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, 2018 was 2.37. The Utility’s earnings to combined fixed charges and preferred stock dividends ratio for the three months ended March 31, 2018 was 2.35. 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. 333-215427.

PG&E Corporation's earnings to fixed charges ratio for the three months ended March 31, 2018 was 2.33. 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. 333-215425.

ITEM 6. EXHIBITS

EXHIBIT INDEX

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| 3.1 | Bylaws of PG&E Corporation amended as of December 16, 2016 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 3.3) |
| 10.1 | Term Loan Agreement, dated as of April 16, 2018, by and among PG&E Corporation, the several banks and other financial institutions or entities from time to time parties thereto, Mizuho Bank, Ltd., Royal Bank of Canada and Sumitomo Mitsui Banking Corporation, as joint lead arrangers and joint bookrunners and Mizuho Bank, Ltd., as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2018 (File No. 001-12609), Exhibit 10.1) |
| 10.2 | Term Loan Agreement, dated as of February 23, 2018, by and among Pacific Gas and Electric Company, the several banks and other financial institutions or entities from time to time parties thereto, The Bank of Tokyo-Mitsubishi UFJ, Ltd. and U.S. Bank National Association, as joint lead arrangers and joint bookrunners and The Bank of Tokyo-Mitsubishi UFJ, Ltd, as administrative agent (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 23, 2018 (File No. 001-02348), Exhibit 10.1) |
| *10.3 | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2018 |
| *10.4 | Form of Performance Share Agreement subject to financial goals for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| *10.5 | Form of Performance Share Agreement subject to safety goals for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| *10.6 | Form of Performance Share Agreement subject to total shareholder return goals for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| *10.7 | Form of Restricted Stock Unit Agreement for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| *10.8 | Form of Stock Option Agreement for 2018 grants under the PG&E Corporation 2014 Long-Term Incentive Plan |
| 12.1 | Computation of Ratios of Earnings to Fixed Charges for Pacific Gas and Electric Company |
| 12.2 | Computation of Ratios of Earnings to Combined Fixed Charges and Preferred Stock Dividends for Pacific Gas and Electric Company |
| 12.3 | Computation of Ratios of Earnings to Fixed Charges for PG&E Corporation |
| 31.1 | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| 31.2 | |

| | |
|---|---|
| | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 302 of the Sarbanes-Oxley Act of 2002 |
| **32.1 | Certifications of the Chief Executive Officer and the Chief Financial Officer of PG&E Corporation required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| **32.2 | Certifications of the Chief Executive Officer and the Chief Financial Officer of Pacific Gas and Electric Company required by Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101.INS | XBRL Instance Document |
| 101.SCH | XBRL Taxonomy Extension Schema Document |
| 101.CAL | XBRL Taxonomy Extension Calculation Linkbase Document |
| 101.LAB | XBRL Taxonomy Extension Labels Linkbase Document |
| 101.PRE | XBRL Taxonomy Extension Presentation Linkbase Document |
| 101.DEF | XBRL Taxonomy Extension Definition Linkbase Document |

*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/ DAVID S. THOMASON
David S. Thomason
Vice President, Chief Financial Officer and Controller
(duly authorized officer and principal financial officer)

Dated: May 3, 2018