UNITED STATES
**SECURITIES AND EXCHANGE COMMISSION**
Washington, D.C. 20549

**FORM 10-K**

**(Mark One)**

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**
**For the Fis cal Year Ended December 31, 2017**

☐ **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 S pecified I n I ts C harter | State or Other Jurisdiction of Incorporation or Organization | IRS Employer Identification Number |
|---|---|---|---|
| 1-12609 | PG&E CORPORATION | California | 94-3234914 |
| 1-2348 | PACIFIC GAS AND ELECTRIC COMPANY | California | 94-0742640 |


**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-1000**
(Registrant's telephone number, including area code)

**77 Beale Street, P.O. Box 770000**
**San Francisco, California 94177**
(Address of principal executive offices) (Zip Code)
**(415) 973-7000**
(Registrant's telephone number, including area code)


**Securities registered pursuant to Section 12(b) of the Act:**

| Title of each c lass | Name of e ach e xchange on w hich r egistered |
|---|---|
| **PG&E Corporation:** Common Stock, no par value | New York Stock Exchange |
| **Pacific Gas and Electric Company:** First Preferred Stock, cumulative, par value $25 per share: Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36% Nonredeemable: 6%, 5.50%, 5% | NYSE MKT LLC |

**Securities registered pursuant to Section 12(g) of the Act: None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act:

| | |
|---|---|
| PG&E Corporation | Yes ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

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 Corporatio n | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | 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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

| | |
|---|---|
| PG&E Corporation | Yes ☑ No ☐ |
| Pacific Gas and Electric Company | Yes ☑ No ☐ |

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K:

| | |
|---|---|
| PG&E Corporation | ☑ |
| Pacific Gas and Electric Company | ☑ |

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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. (Check one):

| **PG&E Corporation** | **Pacific Gas and Electric Company** |
|---|---|
| Large accelerated filer ☑ | Large accelerated filer ☐ |
| Accelerated filer ☐ | Accelerated filer ☐ |
| Non-accelerated filer ☐ | Non-accelerated filer ☑ |
| Smaller reporting company ☐ | Smaller reporting company ☐ |
| Emerging growth 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 ☐ No ☑ |
| Pacific Gas and Electric Company | Yes ☐ No ☑ |

**Aggregate market value of voting and non-voting common equity held by non-affiliates of the registrants as of June 30, 2017, the last business day of the most recently completed second fiscal quarter:**

| | |
|---|---|
| PG&E Corporation common stock | $33,956 million |
| Pacific Gas and Electric Company common stock | Wholly owned by PG&E Corporation |

**Common Stock outstanding as of February 1, 2018:**

| | |
|---|---|
| PG&E Corporation: | 514,969,045 shares |
| Pacific Gas and Electric Company: | 264,374,809 shares (wholly owned by PG&E Corporation) |

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved:

| | |
|---|---|
| Designated portions of the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders | Part III (Items 10, 11, 12, 13 and 14) |

**Contents**

*UNITS OF MEASUREMENT*

| | | |
|---|---|---|
| 1 Kilowatt-Hour (kWh) | = | One kilowatt continuously for one hour |
| 1 Megawatt (MW) | = | One thousand kilowatts |
| 1 Megawatt-Hour (MWh) | = | One megawatt continuously for one hour |
| 1 Gigawatt-Hour (GWh) | = | One gigawatt continuously for one hour |
| 1 Kilovolt (kV) | = | One thousand volts |
| 1 MVA | = | One megavolt ampere |
| 1 Mcf | = | One thousand cubic feet |
| 1 MMcf | = | One million cubic feet |

*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's and Pacific Gas and Electric Company's combined Annual Report on Form 10-K for the year ended December 31, 2017 |
| AB | Assembly Bill |
| AFUDC | allowance for funds used during construction |
| ARO | asset retirement obligation |
| ASU | accounting standard update issued by the FASB (see below) |
| CAISO | California Independent System Operator |
| California Water Board | California State Water Resources Control Board |
| Cal Fire | California Department of Forestry and Fire Protection |
| CARB | California Air Resources Board |
| CCA | Community Choice Aggregator |
| Central Coast Board | Central Coast Regional Water Quality Control Board |
| CEC | California Energy Resources Conservation and Development Commission |
| CEMA | Catastrophic Event Memorandum Account |
| $CO_2$ | carbon dioxide |
| CPUC | California Public Utilities Commission |
| CRRs | congestion revenue rights |
| DER | distributed energy resources |
| DIDF | Distribution Investment Deferral Framework |
| Diablo Canyon | Diablo Canyon nuclear power plant |
| DOE | U.S. Department of Energy |
| DOGGR | Division of Oil, Gas and Geothermal Resources |
| DOI | U.S. Department of the Interior |
| DRP | electric distribution resources plan |
| DTSC | Department of Toxic Substances Control |
| EDA | equity distribution agreement |
| EMANI | European Mutual Association for Nuclear Insurance |
| EPA | Environmental Protection Agency |
| 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 |
| IOUs | investor-owned utility(ies) |
| IRS | Internal Revenue Service |
| LTIP | long-term incentive plan |
| MD&A | Management's Discussion and Analysis of Financial Condition and Results of Operations set forth in Part II, Item 7, of this Form 10-K |
| NAV | net asset value |
| NDCTP | Nuclear Decommissioning Cost Triennial Proceeding |
| NEIL | Nuclear Electric Insurance Limited |
| NEM | net energy metering |
| NRC | Nuclear Regulatory Commission |
| NTSB | National Transportation Safety Board |
| 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 |
| PD | proposed decision |
| PFM | petition for modification |
| PHMSA | Pipeline and Hazardous Materials Safety Administration |
| PSEP | pipeline safety enhancement plan |
| QF | qualifying facility |
| RAMP | Risk Assessment Mitigation Phase |
| REITS | real estate investment trust |
| ROE | return on equity |
| RPS | renewable portfolio standard |
| SB | Senate Bill |
| 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 |
| 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

### ITEM 1. BUSINESS

PG&E Corporation, incorporated in California in 1995, is a holding company whose primary operating subsidiary is Pacific Gas and Electric Company, a public utility operating in northern and central California. The Uti lity was incorporated in California in 1905. PG&E Corporation became the holding company of the Utility and its subsidiaries in 1997. The Utility generates revenues mainly through the sale and delivery of electricity and natural gas to customers. PG&E C orporation's and the Utility's operating revenues, income, and total assets can be found below in Item 6. Selected Financial Data.

The principal executive offices of PG&E Corporation and the Utility are located at 77 Beale Street, P.O. Box 770000, San Fra ncisco, California 94177. PG&E Corporation's telephone number is (415) 973-1000 and the Utility's telephone number is (415) 973-7000.

At December 31, 201 7 , PG&E Corporation and the Utility had approximately 23,000 regular employees, approximately 20 of w hich were employees of PG&E Corporation . Of the Utility's regular employees, approximately 15,000 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers; the Engi neers and Scientists of California; and the Service Employees International Union . The collective bargaining agreements currently in effect will expire on December 31, 2019.

This is a combined Annual Report on Form 10-K for PG&E Corporation and the Uti lity. PG&E Corporation's and the Utility's Annual Reports on Form 10-K, Quarterly Reports on Fo rm 10-Q, Current Reports on Form 8-K, and proxy statements, are available free of charge on both PG&E Corporation's website, *www.pgecorp.com* , and the Utility 's website, *www.pge.com* , as promptly as practicable after they are filed with, or furnished to, the SEC. 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 ma ter ial 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 so lel y for the information of investors and do not intend the address to be an active link. PG&E Corporat ion 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.

This 2017 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertaintie s. For a discussion of the significant risks that could affect the outcome of these forward-looking statements and PG&E Corporation's and the Utility's future financial condition and results of operati ons, see Item 1A. Risk Factors and the section entitle d "Forward-Looking Statements" in Item 7. MD&A.

#### Regulatory and Enforcement Environment

The Utility's business is subject to the regulatory jurisdiction of various agencies at the federal, state, and local levels. At the state level, the Utility is reg ulated primarily by the CPUC. At the federal level, the Utility is subject to the jurisdiction of the FERC and the NRC. The Utility is also subject to the requirements of other federal, state and local regulatory agencies , including with respect to safety , the environment , and health. This section and the "Ratemaking Mechanisms" section below summarize some of the more significant laws, regulations, and regulatory proc eedings affecting the Utility.

PG&E Corporation is a "public utility holding company" a s defined under the Public Utility Holding Company Act of 2005 and is subject to regulatory oversight by the FERC. PG&E Corporation and its subsidiaries are exempt from all requirements of the Public Utility Holding Company Act of 2005 other than the obli gation to provide access to their books and records to the FERC and the CPUC for ratemaking purposes.

*The California Public Utilities Commission*

The CPUC is a regulatory agency that regulates privately owned public utilities in California. The CPUC has jurisdiction over the rates and terms and conditions of servi ce for the Utility's electric and natural gas dist ribution operations, electric generation, and natural gas transmission and storage services. The CPUC also has jurisdiction over the Utility's issuances of securities, dispositions of utility assets and facilities, energy purchases on behalf of the Utility's electric and natural gas retail customers, rates of return, rates of depreciation, oversight of nuclear decommissioning, and aspects of the siting of facilities used in providing electric and natural gas utility service.

The CPUC enforces state laws and regulations that set forth safety requirements pertaining to the design, construction, testing, operation, and maintenance of utility gas and electric facilities. The CPUC can impose penalties of up to $50,000 per day, per violation, for violations that occurred after January 1, 2012. (The statutory maximum penalty for violations that occurred before January 1, 2012 is $20,000 per violation.) The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the g ood faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC also is required to consider the appropriateness of the amount of the penalty to the size of the entity charged.

The CPUC has delegated auth ority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under the current gas and el ectric citation programs adopted by the CPUC in September 2016, the SED has discretion whether to issue a penalty for each violation, but if it 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 p enalties on a daily basis, or on less than a d aily basis, for violations that continued for more than one day. The SED has the discretion to either address each violation in a distinct citation or to include multiple violations in a single citation regard less of whether the violations occurred in the same incident or are of a similar nature. Penalty payments for citations issued pursuant to the gas and electric safety citation programs are the responsibility of shareholders of an issuer and must not be rec overed in rates or otherwise directly or indir ectly charged to customers.

The California State Legislature also directs the CPUC to implement state laws and policies, such as the laws relating to increasing renewable energy resources, the development an d widespread deployment of distributed generation and self-generation resources, the reduction of GHG emissions, the establishment of energy storage procurement targets , and the development of a state-wide electric vehicle charging infrastructure. T he CPU C is responsible for approving funding and administration of state-mandated public purpose programs such as energy efficiency and other customer programs. The CPUC also conducts audits and reviews of the Utility’s accounting, performance , and compliance w ith regulatory guidelines .

T he CPUC has imposed various conditions that govern the relationship between the Utility and PG&E Corporation and other affiliates, including financial conditions that require PG&E Corporation’s Board of Directors to give first priority to the capital requirements of the Utility, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. (For more information, see “Liquidity and Financial Resour ces” in Item 7. MD&A and Item 1A. Risk Factors.)

*The Federal Energy Regulatory Commission and the California Independent System Operator*

The FERC has jurisdictio n over the Utility's electric transmission revenue requirements and rates, the licensing of substantially all of the Utility's hydroelectric generation facilities, and the interstate sale and transportation of natural gas. The FERC regulates the interconnections of the Utility’s trans mission systems with other electric system and generation facilities, the tariffs and conditions of service of regional transmission organizations and the terms and rates of wholesale electricity sales. The FERC also is charged with adopting and enforcing mandatory standards governing the reliabi lity of the nation’s electric transmission grid, including standards to protect the nation’s bulk power system against potential disruptions from cyber and physical security breaches. The FERC has authority to impo se fines of up to $1 million per day for violation s of certain federal statutes and regulations.

The CAISO is the FERC-approved regional transmission organization for the Utility’s service territory. The CAISO controls the operation of the electric trans mission system in California and provides open access transmission service on a non - discriminatory basis. The CAISO also is responsible for planning transmission system additions, ensuring the maintenance of adequate reserves of generating capacity, and e nsuring that the reliability of the transmission system is maintained.

*The Nuclear Regulatory Commission*

The NRC oversees the licensing, construction, operation and decommissioning of nuclear facilities, including the Utility's two nuclear generating units at Diablo Canyon and the Utility's retired nuclear generating unit at Humboldt Bay. (See "Electric ity Resources" below.) NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspec ts of these facilities. In the event of non-compliance, the NRC has the authority to impose fines or to force a shutdown of a nuclear plant, or both. NRC safety and security requirements have, in the past, necessitated substantial capital expenditures at Diablo Canyon, and substantial capital expenditures could be required in the future. (For more information about Diablo Canyon, see "Regulatory Matters – Diablo Canyon Nuclear Power Plant" in Item 7. MD&A and Item 1A. Risk Factors below.)

*Third- party m onitor*

On April 12, 2017, the Utility retained a third-party monitor at the Utility's expense as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction, which sentenced the Utility to, among other th ings, a five-year corporate probation period and oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years. The goal of the monitor is to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of its gas and el ectric operations and maintains effective ethics, compliance , and safety related incentive programs on a Utility-wide basis. (For additional information see Item 1A. Risk Factors.)

***Other Regula tors***

The CEC is the state's primary energy policy and planning agency. The CEC is responsible for licensing all thermal power plants over 50 MW within California. The CEC also is responsible for forecasts of future energy needs used by the CPUC in determining the adequacy of the utilities' electricity procurement plans and for adopting building and appliance energy efficiency requirements.

The CARB is the state agency responsible for setting and monitoring GHG and other emission limits. The CARB is also responsible for adopting and enforcing regulations to implement state law requirements to gradually reduce GHG emissions in California. (See "Environmental Regulation - Air Quality and Climate Change" below.)

In addition, the Utility obtains perm its, authorizations, and licenses in connection with the construction and operation of the Utility's generation facilities, electricity transmission lines, natural gas transportation pipelines, and gas compressor station facilities. The Utility also perio dically obtains permits, authorizations, and licenses in connection with distribution of electricity and natural gas that grant the Utility rights to occupy and/or use public property for the operation of the Utility's business and to conduct certain relat ed operations. The Utility has franchise agreements with approximately 300 cities and counties that permit the Utility to install, operate, and maintain the Utility's electric and natural gas facilities in the public streets and highway s. In exchange for the right to use public streets and highway s, the Utility pays annual fees to the cities and counties. In most cases, the Utility's franchise agreements are for an indeterminate term, with no expiration date. (For additional information see Item 1A. Ris k Factors.)

**Ratemaking Mechanisms**

The Utility's rates for electric and natural gas utility services are set at levels that are intended to allow the Utility to recover its costs of providing service and a return on invested capital ("cost-of-service ratemaking"). Before setting rates, the CPUC and the FERC conduct proceedings to determine the annual amount that the Utility will be authorized to collect from its customers ("revenue requirements"). The U tility's revenue requirements consist primarily of a base amount set to enable the Utility to recover its reasonable operating expenses ( e.g., maintenance, administration and general expenses) and capital costs ( e.g., depreciation, tax, and financing expen ses). In addition, the CPUC authorizes the Utility to collect revenues to recover costs that the Utility is allowed to "pass-through" to customers (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Item 7. MD&A) , including its co sts to procure electricity, natural gas and nuclear fuel, to administer public purpose and customer programs, and to decommission its nuclear facilities.

The Utility's rate of return on electric transmission assets is determined in the FERC TO proceeding s. Similarly, the authorized rate of return on all other Utility assets is set in the CPUC's cost of capital proceeding. Other than its electric transmission and certain gas transmission and storage revenues, the Utility's base revenues are "decoupled" f rom its sales volume. Regulatory balancing accounts, or revenue adjustment mechanisms, are designed to allow the Utility to fully collect its authorized base revenue requirements. As a result, the Utility's base revenues are not impacted by fluctuations in sales resulting from rate changes or usage. The Utility's earnings primarily depend on its ability to manage its base operating and capital costs (referred to as "Utility Revenues and Costs that Impacted Earnings" in Item 7. MD&A) within its authorized base revenue requirements.

Due to the seasonal nature of the Utility's business and rate design, customer electric bills are generally higher during summer months (May – October) because of higher demand, driven by air conditioning loads. Customer bills related to gas service generally increase during the winter months (November – March) to account for the gas peak due to heating.

During 201 7 , the CPUC continued to implement state law requirements to reform residential electric rates to more closely ref lect the utilities' actual costs of service, reduce cross-subsidization among customer rate classe s, implement new rules for net energy metering (which currently allow certain self-generating customers to receive bill credits for surplus power at the full retail rate) , and allow customers to have greater control over their energy use. (See " Regulatory Matters " in Item 7. MD&A for more information on specific CPUC proceedings . )

From time to time, the CPUC may use incentive ratemaking mechanisms that provide the Utility an opportunity to earn some additional revenues. For example, the Utility has earned incentives for the successful implementation of energy efficiency programs. (See "Regulatory Matters – 2015 – 2016 Energy Efficiency Incentives Awards" in Item 7. MD&A.)

***Base Revenues***

*General Rate Cases*

The GRC is the primary proceeding in which the CPUC determines the amount of base revenue requirements that the Utility is authorized to collect from customers to recover the Utility's anticipated co sts, including return on rate base, related to its electric distribution, natura l gas distribution, and Utility- owned electric generation operations. The CPUC generally conducts a GRC every three or four years. The CPUC approves the annual revenue requir ements for the first year (or "test year") of the GRC period and typically authorizes the Utility to receive annual increases in revenue requirements for the subsequent years of the GRC period (known as "attrition years"). Attrition year rate adjustments are generally provided for cost increases related to increases in invested capital and inflation. Parties in the Utility's GRC include the ORA and TURN, who generally represent the overall interests of residential customers, as well as a myriad of other i ntervenors who represent other business, community, customer, environmental, and union interests. The Utility plans to file the 20 20 GRC in the third quarter of 2018. In December 2014, t he CPUC established two new procedures concerning safety-related act ivities, the Safety Model Assessment Proceeding and the RAMP, preceding a utility's GRC . The purpose of the Safety Model Assessment Proceeding is to undertake a comprehensive analysis of each utility's risk-based decision making approach. The RAMP submit tal includes a utility's prioritization of the risks it is facing , and a prioritization of risk mitigation alternatives, as well as a risk mitigation plan. The Utility filed its first RA MP submittal with the CPUC on November 30, 2017.

( For more informati on about the Utility's GRC, see " Regulatory Matters −2017 General Rate Case" and " Regulatory Matters −20 20 General Rate Case" in Item 7. MD&A. )

*Natural Gas Transmission and Storage Rate Cases*

The CPUC determines the Utility's authorized revenue requirements and rates for its natural gas transmission and storage services in the GT&S rate case. The CPUC generally conducts a GT&S rate case every three or four years. Similar to the GRC, t he CPUC approves the annual revenue requirements for the fir st year (or "test year") of the GT&S rate case period and typically determines annual increases in revenue requirements for attrition years of the GT&S rate case period. Parties in the Utility's GT&S rate case include the ORA and TURN, who generally repre sent the overall interests of residential customers, as well as other intervenors who represent other business, community, customer, environmental, and union interests. The Utility filed the 2019 GT&S rate case application on November 17, 2017. (For more information, see "Regulatory Matters – 2015 Gas Transmission and Storage Rate Case" and "Regulatory Matters – 2019 Gas Transmission and Storage Rate Case" in Item 7. MD&A.)

*Cost of Capital Proceedings*

The CPUC periodically conducts a cost of capit al proceeding to authorize the Utility's capital structure and rates of return for its electric generation, electric and natural gas distribution, and natural gas transmission and storage rate base. The CPUC has authorized the Utility's capital structure through 2019, consisting of 52% common equity, 47% long-term debt, and 1% preferred stock. The CPUC also set the authorized ROE through 2017 at 10.40% and 10.25% beginning on January 1, 2018 and reset the cost of debt to 4.89% . The CPUC adopted an adjust ment mechanism to allow the Utility's capital structure and ROE to be adjusted if the utility bond index changes by certain thresholds on an annual basis.

(For more information, s ee "Regulatory Matters – CPUC Cost of Capital " in Item 7. MD&A. )

*Electrici ty Transmission Owner Rate Cases*

The FERC determines the amount of authorized revenue requirement s , including the rate of return on electric transmission assets, that the Utility may collect in rates in the TO rate case. The Utility has historically file d a TO rate case every year. The FERC typically authorizes the Utility to charge new rates based on the requested revenue requirement, subject to refund, before the FERC has issued a final decision. These FERC-approved rates are included by the CPUC in t he Utility's retail electric rates and by the CAISO in its Transmission Access Charges to wholesale customers . ( For more information, s ee " Regulatory Matters – Transmission Owner Rate Cases" in Item 7. MD&A.) The Utility also recovers a portion of its rev enue requirements for its wholesale electric transmission costs through charges collected under specific contracts with wholesale transmission customers that the Utility entered into before the CAISO began its operations. These wholesale customers are cha rged individualized rates based on the terms of their contracts.

***Revenues to Recover Energy Procurement and Other Pass-Through Costs***

*Electricity Procurement Costs*

California investor-owned electric utilities are responsible for procuring electr ical cap acity required to meet bundled customer demand, plus applicable reserve margins, that are not satisfied from their own generation facilities and existing electric contracts. The utilities are responsible for scheduling and bidding electric generation reso urces, including certain electricity procured from third parties into the wholesale market, to meet customer demand according to which resources are the least expensive (i.e., using the principles of "least-cost dispatch"). In addition, the utilities are required to obtain CPUC approval of their bundled customer procurement plans based on long-term demand forecasts. In October 2015, the CPUC approved the Utility's most recent bundled customer procurement plan. It was revised since its initial approval an d will remain in effect as revised until superseded by a subsequent CPUC-approved plan.

California law allows electric utilities to recover the costs incurred in compliance with their CPUC-approved bundled customer procurement plans without further after-the-fact reasonableness review by the CPUC . The CPUC may disallow c osts associated with electricity purchases if the costs were not incurred in compliance with the CPUC-approved plan or if the CPUC determines that the utility failed to foll ow the principles of least-cost dispatch. Additionally, the CPUC may disallow the cost of replacement power procured due to unplanned outages at Utility-owned generation facilities.

The Utility recovers its electric procurement costs annually primarily t hrough the energy resource recovery account . (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.) Each year, the CPUC reviews the Utility's forecasted procurement costs related to power purchase agreements, derivative instruments , GHG emissions costs, and generation fuel expense, and approves a forecasted revenue requirement. The CPUC may adjust the Utility's retail electric rates more frequently if the forecasted aggregate over-collections or under-collections in the energy reso urce recovery account exceed 5% of its prior year electric procurement and U tility-owned generation revenues. The CPUC performs an annual compliance review of the transactions recorded in the energy resource recovery account.

The CPUC has approved variou s power purchase agreements that the Utility has entered into with third parties in accordance with the Utility's CPUC-approved procurement plan, to meet mandatory renewable energy targets , and to comply with resource adequacy requirements. (For more info rmation, s ee "Electric Utility Operations – Electricity Resources" below as well as Note 13 of the Notes to the Consolidated Financial Statements in Item 8. )

*Natural Gas Procurement , Storage, and Transportation Costs*

The Utility recovers the cost of gas used in generation facilities as a cost of electricity that is recovered annually through retail electric rates.

The Utility sets the natural gas procurement rate for small commercial and residential customers (referred to as "core" customers) monthly, based on the forecasted costs of natural gas, core pipeline capacity and storage costs. The Utility recovers the cost of gas purchased on behalf of core customers as well as the cost of derivative instruments for its core gas portfolio, through its retail gas rates, subject to limits as set forth in its core procurement incentive mechanism described below . The Utility reflects the difference between actual natural gas purchase costs and forecasted natural gas purchase costs in several natural gas balancin g accounts, with under-collections and over-collections taken into account in subsequent monthly rate change s.

The core procurement incentive mechanism protects the Utility against after-the-fact reasonableness reviews of its gas procurement costs for i ts core gas portfolio . Under the core procurement incentive mechanism , the Utility's natural gas purchase costs for a fixed 12-month period are compared to an aggregate market-based benchmark based on a weighted average of published monthly and daily natu ral gas price indices at the points where the Utility typically purchases natural gas. Costs that fall within a tolerance band, which is 99% to 102% of the commodity benchmark, are considered reasonable and are fully recovered in customers' rates. One-ha lf of the costs above 102% of the benchmark are recoverable in customers' rates, and the Utility's customers receive in their rates 80% of any savings resulting from the Utility's cost of natural gas that is less than 99% of the benchmark. The Utility ret ains the remaining amount of these savings as incentive revenues, subject to a cap equal to 1.5% of total natural gas commodity costs. While this mechanism remains in place, changes in the price of natural gas, consistent with the market-based benchmark, are not expected to materially impact net income.

The Utility incurs transportation costs under various agreements with interstate and Canadian third-party transportation service providers. These providers transport natural gas from the points at which the Utility takes delivery of natural gas (typically in Canada, the U.S. Rocky Mountains, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements are governed by FERC-approved tar iffs that detail rates, rules, and terms of service for the provision of natural gas transportation services to the Utility on interstate and Canadian pipelines. The FERC approves the United States tariffs that shippers , including the Utility, pay for pip eline service , and the applicable Canadian tariffs are approved by the National Energy Board , a Canadian regulatory agency . The transportation costs the Utility incurs under these agreements are recovered through CPUC-approved rates as core natural gas pr ocurement costs or as a cost of electricity.

*Costs Associated with Public Purpose and Customer Programs*

The CPUC authorizes the Utility to recover the costs of various public purpose and other customer programs through the collection of rates from most Utility customers. These programs relate to energy efficiency, demand response, distributed generation, energy research and development, and other matters. Additionally, the CPUC has authorized the Utility to provide a discount rate for low-income custom ers, known as California Alternate Rates for Energy ("CARE"), which is subsidized by the Utility's other customers.

*Nuclear Decommissioning Costs*

The Utility's nuclear power facilities consist of two units at Diablo Canyon and the retired facility at Hum boldt Bay. Nuclear decommissioning requires the safe removal of nuclear facilities from service and the reduction of residual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. Nuclear d ecommissioning costs are collected in advance through rates and are held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. The Utility files an application with the CPUC every three years requesting approv al of the Utility's updated estimated decommissioning costs and any rate change necessary to fully fund the nuclear decommissioning trusts to the levels needed to decommission the Utility's nuclear plants.

On January 11 , 201 8 , the CPUC approved the retire ment of Diablo Canyon 's two nuclear power reactor units by 2024 and 2025 . (For more information, see " Regulatory Matters " in Item 7. MD&A.)

**Electric Utility Operations**

The Utility generates electricity and provides electric transmission and distribution services throughout its service territory in northern and central California to residential, commercial, industrial, and agricultural customers. The Utility provides "bundled" services (i.e., electricity, transmission and distribution services) to most c ustomers in its service territory. Customers also can obtain electricity from alternative providers such as municipalities or CCAs, as well as from self-generation resources, such as rooftop solar installations.

The Utility has continued to invest in its vision for a future electric grid which w ill allow customers to choose new, advanced energy supply technologies and services to meet their needs consistent with safe, reliable and affordable electric service. In 2017, the Ut ility continued to work on the foundation for its program to deploy up to 7,500 charging stations. (For more information, see " Regulatory Matters " in Item 7. MD&A.)

***Electricity Resources***

The Utility is required to maintain generating capacity adequate to meet its customers' demand for electricity ("load"), including peak demand and planning and operating reserves, deliverable to the locations and at times as may be necessary to provide reliable electric service. The Utility is required to dispatch, or schedule all of the electric resources within its portfolio in the most cost-effective way **.**

The following table shows the percentage of the Utility's total deliveries of electricity to customers in 201 7 represented by each major electric resource, and fu rther discussed below.

Total 201 7 Actual Electricity Generated and Procured – 61,397 GWh [1] :

| | Percent of Bundled Retail Sales | |
|---|---|---|
| Owned Generation Facilities | | |
| Nuclear | 27.4% | |
| Large Hydroelectric | 15.1% | |
| Fossil fuel-fired | 8.7% | |
| Small Hydroelectric | 1.7% | |
| Solar | 0.5% | |
| Total | | 53.4% |
| | | |
| Qualifying Facilities | | |
| Non-Renewable | 3.9% | |
| Renewable | 1.9% | |
| Total | | 5.8% |
| Other Third-Party Purchase Agreements | | |
| Renewable | 29.0% | |
| Non-Renewable | 7.3% | |
| Large Hydroelectric | 3.3% | |
| Total | | 39.6% |
| Others, Net [2] | | 1.2% |
| **Total [3]** | | **100%** |

[1] This amount excludes electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
[2] Mainly comprised of net CAISO open market purchases.
[3] Non-renewable sources, including nuclear, large hydroelectric, and fossil fuel-fired are offset by tran smission and distribution related system losses.

*Renewable Energy Resources*

California law established a n RPS that requires load-serving entities, such as the Utility, to gradually increase the amount of renewable energy they deliver to their customers . In October 2015, the California Governor signed SB 350, the Clean Energy and Pollution Reduction Act of 2015 into law. SB 350 became effective January 1, 2016, and increases the amount of renewable energy that must be delivered by most load-serving ent ities, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period, to 50% of their total annual retail sales by the end of the 2028- 2030 compl iance period, and in each three-ye ar com pliance period thereafter, unless changed by legislative action. SB 350 provides compliance flexibility and waiver mechanisms, including increased flexibility to apply excess renewable energy procurement in one compliance period to future compliance perio ds. The Utility will incur additional costs to procure renewable energy to meet the new renewable energy targets, which the Utility expects will continue to be recoverable from customers as "pass-through" costs. The Utility also may be subject to penaltie s for failure to meet the higher targets. The CPUC is required to open a new rulemaking proceeding to adopt regulations to implement the higher renewable targets.

Renewable generation resources, for purposes of the RPS requirements , include bioenergy such as biogas and biomass, certain hydroelectric facilities (30 MW or less), wind, solar, and geothermal energy. During 201 7 , 33.1 % of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 2 7 %. Approxima tely 29 % of the renewable energy delivered to the Utility's customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs ( 1.9 %), the Utility's small hydroelectric facilities ( 1.7 %), and the Utility's solar facilit ies ( 0.5 %).

The total 201 7 renewable deliveries shown above were comprised of the following:

| Type | GWh | Percent of Bundled Retail Sales |
|---|---|---|
| Solar | 8,294 | 13.5% |
| Wind | 5,047 | 8.2% |
| Geothermal | 2,796 | 4.6% |
| Biopower | 2,217 | 3.6% |
| RPS-Eligible Hydroelectric | 1,943 | 3.2% |
| Total | **20,297** | **33.1%** |

*Energy Storage*

As required by California law, the CPUC has opened a proceeding to establish a multi-year energy storage procurement framework, including energy storage procurement targets to be achieved by each load-serving entity under the CPUC jurisdiction, including the Utility. Under the adopted energy storage procurement framework, the Utility is required to procure 580 MW of qualifying storage capacity by 2020, with all energy storage projects required to be operational by the end of 2024.

The CPUC also adopted biennial interim storage targets for the Utility, beginning in 2014 and ending in 2020. Under the adopted framework, the Utility is required to conduct biennial competitive request for offer to he lp meet its interim storage targets.

The Utility's 201 7 energy storage target is 120 MW , plus an additional amount to replace failed and rejected agreements for a total of approximately 160 MW . On November 30, 2016, the Utility issued its 2016 request for offer . On December 1, 2017, the Utility submitted contracts for 165 MW of energy storage projects for CPUC review. One of the projects is a 20 MW distribution deferral project that would be Utility-owned.

The Utility currently owns or operates thre e battery storage facilities, each less than 10 MW.

*Owned Generatio n Facilities*

At December 31, 201 7 , the Utility owned the following generation facilities, all located in California, listed by energy source and further described below:

| Generation Type | County Location | Number of Units | Net Operating Capacity (MW) |
|---|---|---|---|
| Nuclear [(1)] : | | | |
| Diablo Canyon | San Luis Obispo | 2 | 2,240 |
| Hydroelectric [(2)] : | | | |
| Conventional | 16 counties in northern and central California | 103 | 2,680 |
| Helms pumped storage | Fresno | 3 | 1,212 |
| Fossil fuel-fired: | | | |
| Colusa Generating Station | Colusa | 1 | 657 |
| Gateway Generating Station | Contra Costa | 1 | 580 |
| Humboldt Bay Generating Station | Humboldt | 10 | 163 |
| Fuel Cell: | | | |
| CSU East Bay Fuel Cell | Alameda | 1 | 1 |
| SF State Fuel Cell | San Francisco | 2 | 2 |
| Photovoltaic [(3):] | Various | 13 | 152 |
| **Total** | | **136** | **7,687** |

[(1 )] The Utility's Diablo Canyon power plant consists of two nuclear power reactor units, Units 1 and 2. The NRC operating licenses expire in 2024 and 2025, respectively. On January 11, 2018, the CPUC approved the Utility's application to retire Unit 1 by 202 4 and Unit 2 by 2025. ( See "Diablo Canyon Nuclear Power Plant " in . Item 7. MD&A and Item 1A. Risk Factors.)
[(2)] The Utility's hydroelectric system consists of 106 generating units at 66 powerhouses. All of the Utility's powerhouses are licensed by the FERC (except for two small powerhouses not subject to FERC licensing requirements), with license terms between 30 and 50 years.
[(3)] The Utility's large photovoltaic facilities are Cantua solar station ( 20 MW), Five Points solar station (15 MW), Gates solar station (20 MW), Giffen solar station (10 MW), Guernsey solar station (20 MW), Huron solar station (20 MW ), Stroud solar station (20 MW), West Gates solar station (10 MW), and Westside solar station ( 15 MW). All of these facilities are located in Fresno County, except for Guernsey solar station, which is located in Kings County.

*Generation Resources from Third Parties.*

The Utility has entered into various agreements to purchase power and electric c apacity, including agreements for renewable energy resources, in accordance with its CPUC-approved procurement plan. ( S ee "Ratemaking Mechanisms" above.) For more information regarding the Utility's power purchase agreements, see Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8.

***Electricity Transmission***

At December 31, 201 7 , the Utility owned approximately 1 9 , 200 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility al so operated 9 2 electric transmission substations with a capacity of approximately 64, 7 00 M VA. The Utility's electric transmission system is interconnected with electric power systems in the Western Electricity Coordinating Co uncil, which includes many western states, Alberta and British Columbia, and parts of Mexico.

Decisions about expansions and maintenance of the transmission system can be influenced by decisions of our regulators. For example, in 2013, the Utility, MidAmerican Transmission, LLC, a nd Citizens Energy Corporation were selected by the CAISO to jointly develop a new 230-kV transmission line to address the growing power demand in the Fresno, Madera and Kings counties area. However, the 2022 in-service date for the 70-mile line was subse quently postponed by the CAISO, and the CAISO has placed the project on hold. The Utility has stopped all work on the project pending a decision from the CAISO that could defer or cancel the project. A decision by the CAISO is expected by March 2018. In addition, as a part of the CAISO's 2016-2017 planning efforts, the CAISO found that a number of lower-voltage transmission projects were no long er required and recommended cancelling or requiring further review in the 2017-2018 planning cycle.

Throughout 201 7 , the Utility upgraded several substations and re-conductored a number of transmission lines to improve maintenance and system flexibility, reliability and safety.  The Utility expects to undertake various additional transmission projects over the next several years to upgrade and expand the capacity of its transmission system to secure access to renewable generation resources and replace aging or obsolete equipment and improve system reliability.  The Utility also has taken steps to improve the physica l security of its transmission substations and equipment.

***Electricity Distribution***

The Utility's electric distribution network consists of a pproximately 1 07 , 2 00 circuit miles of distribution lines (of which approximately 20% are underground and approxima tely 80% are overhead), 5 9 transmission switching substations, and 605 distribution substations, with a capacity of approximately 3 1 , 8 00 MVA. The Utility’s distribution network interconnects with its transmission system, primarily at switching and distrib ution substations, where equipment reduces the high-voltage transmissio n voltages to lower voltages, ranging from 44 kV to 2.4 kV, suitable for distribution to the Utility’s customers.

These distribution substations serve as the central hubs for the Utility’s electric distribution network.  Emanating from each substation are primary and secondary distribution lines connected to local transformers and switching equipment that link distribution lines and provide delivery to end-users.  In some cases, the Utility sells electricity from its distribution facilities to entities, such as municipal and other utilities, that resell the electricity.  The Utility operates electric distribution control center facilit ies in Concord , Roc klin, and Fresno , California ; t hese control centers form a key part of the Utility’s efforts to create a smarter, more resilient grid.

In 2017, the Utility continued to deploy its f ault l ocation, i solation, and s ervice r estoration circuit technology that involves the rapid operation of smart switches to reduce the duration of customer outages.  Another 92 circuits were outfitted with this equipment, bringing the total deployment to 882 of the Utility’s 3,200 distribution circuits.  The Utility plans to con tinue performing work to improve the reliability and safety of its electric distribution operations in 2018.

***Electricity Operating Statistics***

The following table shows certain of the Utility's operating statistics from 201 5 to 201 7 for electricity sold or delivered, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for electricity sold in 201 7 , 201 6 and 201 5 .

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Customers (average for the year) | 5,384,525 | 5,349,691 | 5,311,178 |
| Deliveries (in GWh) [1] | 82,226 | 83,017 | 85,860 |
| Revenues (in millions): | | | |
| Residential | $ 5,693 | $ 5,409 | $ 5,032 |
| Commercial | 5,431 | 5,396 | 5,278 |
| Industrial | 1,603 | 1,525 | 1,555 |
| Agricultural | 1,069 | 1,226 | 1,233 |
| Public street and highway lighting | 79 | 80 | 83 |
| Other [2] | (294) | (68) | (84) |
| Subtotal | 13,581 | 13,568 | 13,097 |
| Regulatory balancing accounts [3] | (344) | 297 | 560 |
| **Total operating revenues** | **$ 13,237** | **$ 13,865** | **$ 13,657** |
| Selected Statistics: | | | |
| Average annual residential usage (kWh) | 6,231 | 6,115 | 6,294 |
| Average billed revenues per kWh: | | | |
| Residential | $ 0.1936 | $ 0.1887 | $ 0.1719 |
| Commercial | 0.1716 | 0.1716 | 0.1640 |
| Industrial | 0.1055 | 0.0990 | 0.0973 |
| Agricultural | 0.2041 | 0.1814 | 0.1610 |
| Net plant investment per customer | $ 7,486 | $ 7,195 | $ 6,660 |

[1] These amounts include electricity provided to direct access customers and CCAs who procure their own supplies of electricity.
[2] This activity is primarily related to provisions for rate refunds and unbilled electric revenue , partially offset by other miscellaneous revenue items.
[3] These amounts represent rev enues authorized to be billed.

**Natural Gas Utility Operations**

The Utility provides natural gas transportation services to "core" customers (i.e., small commercial and residential customers) and to "non-core" customers (i.e., industrial, large commerci al, and natural gas-fired electric generation facilities) that are connected to the Utility's gas system in its service territory. Core customers can purchase natural gas procurement service (i.e. , natural gas supply) from either the Utility or non-utility third-party gas procurement service providers (referred to as core transport agents). When core customers purchase gas supply from a core transport agent, the Utility continues to provide gas delivery, metering and billing services to customer s. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. Currently, more th an 95% o f core customers, representing approximately 80 % of the annual core market d emand, receive bundled natural gas service from the Utility.

The Utility generally does not provide procurement service to non-core customers, who must purchase their gas supplies from third-party suppliers , unless the customer is a natural gas-fired gene ration facility that the Utility has a power purchase agreement with that includes its generation fuel expense . The Utility offers backbone gas transmission, gas delivery (local transmission and distribution), and gas storage services as separate and dist inct services to its non-core customers. Access to the Utility's backbone gas transmission system is available for all natural gas marketers and shippers, as well as non-core customers. The Utility also delivers gas to off-system customers ( i.e ., outside of the Utility's service territory) and to third-party natural gas storage customers.

*Natural Gas Supplies*

The Utility can receive natural gas from all the major natural gas basins in western North America, including basins in western Canada, the Rocky Mountains, and the southwestern United States. The Utility can also receive natural gas from fields in California. The Utility purchases natural gas to serve its core customers directly from producers and marketers in both Canada and the United States. The contract lengths and natural gas sources of the Utility's portfolio of natural gas purchase contracts have varied generally based on market conditions. During 201 7 , the Utility purchased appr oximately 291,100 MMcf o f natural gas (net of the sale of e xcess supply of gas). Substantially all of this natural gas was purchased under contracts with a term of one year or less. The Utility's largest individual supplier represented approximately 14% of the total natural gas volume the Utility purchased durin g 201 7 .

*Natural Gas System Assets*

The Utility owns and operates an integrated natural gas transmission, storage, and distribution system that includes most of northern and central California. At December 31, 201 7 , the Utility's natural gas system consisted of approximately 42, 800 miles of distribution pipelines, over 6, 4 00 miles of backbone and local transmission pipelines, and various storage facilities. The Utility owns and operates eight natural gas compressor stations on its backbone transmission system and one small station on its local transmission system that are used to move gas through the Utility's pipelines. The Utility's backbone transmission system, composed primarily of Lines 300, 400, and 401, is u sed to transport gas from the Utility's interconnection with interstate pipelines, other local distribution companies, and California gas fields to the Utility's local transmission and distribution systems.

The Utility has firm transportation agreements f or delivery of natural gas from western Canada to the United States-Canada border with TransCanada NOVA Gas Transmission, Ltd. interconnecting downstream with TransCanada Foothills Pipe Lines Ltd., B.C. System. The Foothills system interconnects at the bo rder to the pipeline system owned by Gas Transmission Northwest, LLC, which provides natural gas transportation services to a point of interconnection with the Utility's natural gas transportation system on the Oregon-California border near Malin, Oregon. The Utility also has firm transportation agreements with Ruby Pipeline, LLC to transport natural gas from the U.S . Rocky Mountains to the interconnection point with the Utility's natural gas transportation system in the area of Malin, O regon, at the Calif ornia border. Similarly, the Utility has firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Ga s Company to transport natural gas from supply points in the Southwestern United States to interconnection points with th e Utility's natural gas transportation system in the area of California near Topock, Arizona. The Utility also has a transportation agreement with Kern River Gas Transmission Company to transport gas from the U.S. Rocky Mountains to the interconnection po int with the Utility's natural gas system in the area of Daggett, California. ( For more information regarding the Utility's natural gas transportation agreements, see Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8. )

The Utility o wns and operates three underground natural gas storage fields and has a 25% interest in a fourth storage field, all of which are connected to the Utility's transmission system. The Utility owns and operates compressors and other facilities at these storag e fields that are used to inject gas into the fields for storage and later withdrawal. In addition, four independent storage operators are interconnected to the Utility's northern California transmission system. Changes to gas storage safety requirements by DOGGR have led the Utility to develop and propose 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. (For more information, see " R egulatory Matters " in Item 7. MD&A.)

In 2017, the Utility continued upgrading transmission pipeline to allow for the use of in-line inspection tools and continued its work on the final NTSB recommendation from its San Bruno investigation to hydrostatical ly test all high consequence pipeline mileage. The Utility currently plans to complete this NTSB recommendation by 2022 for remaining short pipeline segments that include tie-in pieces, fittings or smaller diameter off-takes from the larger transmission p ipelines.

***Natural Gas Operating Statistics***

The following table shows the Utility's operating statistics from 201 5 through 201 7 (excluding subsidiaries) for natural gas, including the classification of revenues by type of service. No single customer of the Utility accounted for 10% or more of consolidated revenues for bundled gas sales in 201 7 , 201 6 and 201 5 .

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Customers (average for the year) | 4,467,657 | 4,442,379 | 4,415,332 |
| Gas purchased (MMcf) | 234,181 | 208,260 | 209,194 |
| Average price of natural gas purchased | $ 2.30 | $ 1.83 | $ 2.11 |
| Bundled gas sales (MMcf): | | | |
| Residential | 160,969 | 149,483 | 144,885 |
| Commercial | 50,329 | 46,507 | 43,888 |
| **Total Bundled Gas Sales** | **211,298** | **195,990** | **188,773** |
| Revenues (in millions): | | | |
| Bundled gas sales: | | | |
| Residential | $ 2,298 | $ 1,968 | $ 1,816 |
| Commercial | 541 | 439 | 403 |
| Other | (25) | 149 | 125 |
| Bundled gas revenues | 2,814 | 2,556 | 2,344 |
| Transportation service only revenue | 976 | 800 | 649 |
| Subtotal | 3,790 | 3,356 | 2,993 |
| Regulatory balancing accounts | 221 | 446 | 183 |
| **Total operating revenues** | **$ 4,011** | **$ 3,802** | **$ 3,176** |
| Selected Statistics: | | | |
| Average annual residential usage (Mcf) | 38 | 36 | 35 |
| Average billed bundled gas sales revenues per Mcf: | | | |
| Residential | $ 14.27 | $ 13.10 | $ 12.53 |
| Commercial | 11.36 | 9.45 | 9.18 |
| Net plant investment per customer | $ 3,093 | $ 2,808 | $ 2,573 |

**Competition**

***Competition in the Electricity Industry***

California law allows qualifying non-residential electric customers of investor-owned electric utilities to purchase electricity from energy service providers rather than from the utilities up to certain annual and overall GWh limits that have been specified for each utility. This arrangement is known as "direct access." In addition, California law permits cities, counties, and certain other public agencies th at have qualified to become a CCA to generate and/or purchase electricity for their local residents and businesses. By law, a CCA can procure electricity for all of its residents and businesses that do not a ffirmatively elect to continue to receive electr icity generated or procured by a utility.

The Utility continues to provide transmission, distribution, metering, and billing services to direct access customers, although these customers can choose to obtain metering and billing services from their energy service provider. The CCA customers continue to obtain transmission, distribution, metering, and billing services from the Utility. In addition to collecting charges for transmission, distribution, metering, and billing services that it provides, the Ut ility is able to collect charges intended to recover the generation-related costs that the Utility incurred on behalf of direct access and CCA customers while they were the Utility's customers. The Utility remains the electricity provider of last resort f or these customers.

The Utility is also impacted by the increasing viability of distributed generation and energy storage. The levels of self-generation of electricity by customers (primarily solar installations) and the us e of customer net ener gy met ering ("NEM"), which allows self-generating customers to receive bill credits at the full retail rate, are increasing. These factors result in a shift of cost responsibility for grid and related services to other customers of the Utility. For examp le, in creasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer NEM, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, puts upward rate pre ssure on remaining customers. N ew rules and rates became effective for new NEM customers of the Utility in December 2016. New NEM customers are required to pay an interconnection fee, comply with time of use rates, and are required to pay certain non-bypassabl e charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. Significantly higher bills for remaining customers may result in a decline of the number of such customers as they may seek alternative energy providers. The CPUC has indicated that it intends to revisit these rules in 2019.

Further, in some circumstances, governmental entities such as cities and irrigation districts, which have authority under the state constitution or state statute to provide retail electric service, may seek to acquire the Utility's distribution facilities, generally through eminent domain. These same entities may, and sometimes do, construct duplicate distribution facilities to serve existing or new Utility customer s.

The effect of such types of retail competition generally is to reduce the amount of electricity purchased by customers from the Utility.

The Utility also competes for the opportunity to develop and construct certain types of electric transmission fa cilities within, or interconnected to, its service territory through a competitive biddin g process managed by the CAISO. The FERC's transmission planning requirements rules, effective in 2011, removed the incumbent public utility transmission owners' fede rally-based right of first refusal to construct certain new transmission facilities and mandated regional and interregional transmission planning. In 2014, the FERC approved the CAISO's process for regional planning and competitive solicitations and the C AISO's interregional planning process.

( For risks in connection with increasing competition, see Item 1A. Risk Factors. )

***Competition in the Natural Gas Industry***

The Utility competes with other natural gas pipeline companies for customers transporting na tural gas into the southern California market on the basis of transportation rates, access to competitively priced supplies of natural gas, and the quality and reliability of transportation services. The Utility also competes for storage services with oth er third-party storage providers, primarily in northern California.

**Environmental Regulation**

The Utility's operations are subject to extensive federal, state and local laws and requirements 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 activities, including the remediation of hazardous and radioactive substances; the discharge of pollutants into the air, water, and soil; the re porting and reduction of $CO_2$ and other GHG emissions; the transportation, handling, storage and disposal of spent nuclear fuel; and the environmental impacts of land use, includi ng endangered species and habitat protection. The penalties for violation of these laws and requirements can be severe and may include significant fines, damages, and criminal or civil sanctions. These laws and requirements also may require the Utility, u nder certain circumstances, to interrupt or curtail operations. (See Item 1A. Risk Factors.) Generally, the Utility recovers most of the costs of complying with environmental laws and regulations in the Utility's rates, subject to reasonableness review. Environmental costs associated with the clean-up of most sites that contain hazardous substances are subject to a ratemaking mechanism described in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 .

***Hazardous Waste Compliance and Re mediation***

The Utility's facilities are subject to various regulations adopted by the U.S. Environmental Protection Agency, including the Resource Conservation and Recovery Act and the Comprehensive Environmental Response, Compensation and Liability Act of 1980 as amended. The Utility is also subject to the regulations adopted by other federal agenc ies responsible for implementing federal environmental laws. The Utility also must comply with environmental laws and regulations adopted by the State of Cal ifornia and various state and local agencies. These federal and state laws impose strict liability for the release of a hazardous substance on the (1) owner or operator of the site where the release occurred, (2) on companies that disposed of, or arranged for the disposal of, the hazardous substances, and (3) in some cases, their corporate successors. Under the Comprehensive Environmental Response, Compensation and Liability Act , these persons (known as "potentially responsible parties") may be jointly an d severally liable for the costs of cleaning up the hazardous substances, monitoring and paying for the harm caused to natural resources, and paying for the costs of health studies.

The Utility has a comprehensive program in place to comply with these fed eral, state, and local laws and regulations. Under federal and California laws, the Utility may be responsible for remediation of hazardous substances even if it did not deposit those substances on the site. The Utility's remediation activities are overs een by the California DTSC , several California regional water quality control boards, and various other federal, state, and local agencies. The Utility has incurred significant environmental remediation liabilities associated with former manufactured gas plant sites, power plant sites, gas gathering sites, sites where natural gas compressor stations are located, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous substances. Groundwater at the Utility's Hinkley a nd Topock natural gas compressor stations contains hexavalent chromium as a result of the Utility's past operating practices. The Utility is responsible for remediating this groundwater contamination and for abating the effects of the contamination on the environment.

For more information about environmental remediation liabilities, see Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8.

***Air Quality and Climate Change***

The Utility's electric generation plants, natural gas pipeline op erations, vehicle fleet, and fuel storage tanks are subject to numerous air pollution control laws, including the federal Clean Air Act, as well as state and local statutes. These laws and regulations cover, among other pollutants, those contributing to t he formation of ground-level ozone, $CO_2$, sulfur dioxide ($SO_2$), mono-nitrogen oxide ($NO_x$), particulate matter, and other GHG emissions.

*Federal Regulation*

At the federal level, the EPA is charged with implementation and enforcement of the Clean Air Act. Although there have been several legislative attempts to address climate change through imposition of nationwide regulatory limits on GHG emissions, comprehensive federal legislation has not yet been enacted. In the absence of federal legislative action, the EPA has used its existing authority under the Clean Air Act to address GHG emissions.

The federal administration of President Donald Trump has led to significant uncertainty with regard to what further actions may occur regarding climate change at the federal level. Upon taking office, President Trump issued an executive order to freeze all regulations issued in the 60 days preceding his inauguration and directed the EPA and the White House to remove climate change-related materials and web pages. In October 2017, the EPA issued a notice of proposed rulemaking to formally repeal the Clean Power Plan regulations. The Trump administration is expected to take further action to substantially limit climate related regulatory and funding activities. In lig ht of the policy reversal at the federal level, the State of California has indicated that it intends to continue and enhance its leadership on climate change nationally and globally.

*State Regulation*

California 's AB 32, the Global Warming Solutions Act of 2006, provides for the gradual reduction of state-wide GHG emissions to 1990 levels by 2020. The CARB has approved various regulations to achieve the 2020 target , including GHG emissions reporting and a state-wide, comprehensive cap-and-trade program t hat sets gradually declining limits (or "caps") on the amount of GHGs that may be emitted by major GHG emission sources within different sectors of the economy. The cap - and-trade program's first compliance period, which began on January 1, 2013, applied t o the electric generation and large industrial sectors. The next compliance period, which began on January 1, 2015, expanded to include the natural gas and transportation sectors, effectively covering all the economy's major sectors until 2020. The Utili ty's compliance obligation as a natural gas supplier applies to the GHG emissions attributable to the combustion of natural gas delivered to the Utility's customers other than natural gas delivery customers that are separately regulated as covered entities and have their own compliance obligation. During each year of the program, the CARB issues emission allowances (i.e., the rights to emit GHGs) equal to the amount of GHG emissions allowed for that year. Emitters can obtain allowances from the CARB at qu arterly auctions or from third parties or exchanges. Emitters may also satisfy a portion of their compliance obligation through the purchase of offset credits; e.g., credits for GHG reductions achieved by third parties (such as landowners, livestock owner s, and farmers) that occur outside of the emitters' facilities through CARB-qualified offset projects such as refo restation or biomass projects. SB 32 (2016) requires that CARB ensure a 40% reduction in greenhouse gases b y 2030 compared to 1990 levels. I n 2017, AB 398 extended the cap-and-trade program to 2030. The Utility expects all costs and revenues associated with the GHG cap-and-trade program to b e passed through to customers. The California RPS program that requires the utilities to gradually inc rease the amount of renewable energy delivered to their customers is also expected to help reduce GHG emissions in California.

*Climate Change Resilience Strategies*

During 201 7 , the Utility continued its programs to mitigate the impact of the Utility's o perations (including customer energy usage) on the environment and to plan for the actions that it will need to take to increase its resilience in light of the likely impacts of climate change on the Utility's operations. The Utility regularly reviews the most relevant scientific literature on climate change such as rising sea level s, major storm events , increasing temperature s and heatwaves, wildfires, drought and land subsidence , to help the Utility identify and evaluate climate change-related risks and develop the necessary resilience strategies. The Utility maintains emergency response plans and procedures to address a range of near-term risks, including wildfires , extreme storms, and heat waves and uses its risk-assessment process to prioritize infra structure investments for longer-term risks associated with climate change. The Utility also engages with leaders from business, government, academia, and non-profit organizations to share information and plan for the future.

The Utility is working to better understand the current and future impacts of climat e change. In 2017, the Utility filed its first RAMP submittal with the CPUC, which examined Utility safety risks. The Climate Resilience RAMP model indicated potential additional Utility safety con sequences due to climate change, including in the near term. The Utility is conducting foundational work to help anticipate and plan for evolving conditions in terms of weather and climate-change related events. This work will guide efforts to design a Ut ility-wide climate change risk integration strategy. This strategy will inform resource planning and investment, operational decisions, and potential additional programs to identify and pursue mitigations that will incorporate the resilience and safety of the Utility's assets, infrastructure, operations, employees, and customers.

With respect to electric operations, climate scientists project that, sometime in the next several decades, climate change will lead to increased electricity demand due to more ex treme, persistent, and frequent hot weather. The Utility believes its str ategies to reduce GHG emissions through energy efficiency and demand response programs, infrastructure improvements, and the use of rene wable energy and energy storage are effective strategies for a dapting to the expected changes in demand for electricity. The Utility is making substantial investments to build a more modern and resilient system that can better withstand extreme weather and related emergencies. Over the long-term, the Utility also faces the risk of higher flooding and inundation potential at coastal and low elevation facilities due to sea level rise combined with high tides, storm runoff and storm surges. As the state continues to face increased risk of wildfire, t he Utility's vegetation management activities will continue to play an important role to help reduce the risk of wildfire and its impact on electric and gas facilities.

C limate scientists predict that climate change will result in varying temperatures and le vels of precipitation in the Utility's service territory . This could, in turn, affect the Utility's hydroelectric generation. To plan for this potential change, the Utility is engaging with state and local stakeholders and is also adopting strategies suc h as maintaining higher winter carryover reservoir storage levels, reducing discretionary reservoir water releases, and collaborating on research and new modeling tools.

With respect to natural gas operations, both safety-related pipeline strength testin g and normal pipeline maintenance and operations release the GHG methane into the atmosphere. The Utility has taken steps to reduce the release of methane by implementing techniques including drafting and cross-compression, which reduce the pressure and v olume of natural gas within pipelines prior to venting. In addition, the Utility continues to achieve reductions in methane emissions by implementing improvements in leak detection and repair, upgrades at metering and regulating stations, and maintenance and replacement of other pipeline materials.

***Emissions Data***

PG&E Corporation and the Utility track and report their annual environmental performance results across a broad spectrum of areas. The Utility reports its GHG emissions to the CARB and the EPA on a mandatory basis. On a voluntary basis, the Utility reports a more comprehensive emissions inventory to The Climate Registry, a non-pro fit organization. The Utility's third-party verified voluntary GHG inventory reported to The Climate Registry for 2 01 6, the most recent data available, totaled more than 50 milli on metric tonnes of $CO_2$ equivalent , three-quarters of which came from customer natural gas use. The following table shows the 201 6 GHG emissions data the Utility reported to the CARB under AB 32 . PG&E Corporation and the Utility also publish additional GHG emissions data in their annual Corporate Responsibility and Sustainability Report.

| Source | Amount (metric tonnes $CO_2$) |
|---|---|
| Fossil Fuel-Fired Plants [1] | 2,261,032 |
| Natural Gas Compressor Stations and Storage Facilities [2] | 295,851 |
| Distribution Fugitive Natural Gas Emissions | 605,690 |
| Customer Natural Gas Use [3] | 38,697,656 |

(1) Includes nitrous oxide and methane emissions from the Utility's generating stations.
(2) Includud es emissions from compressor stations and storage facilities that are reportable to CARB .
(3) Includes emissions from the combustion of natural gas delivered to all entities on the Utility's distribution system, with the exception of ga s delivered to other natural gas local distribution companies.

The following table shows the Utility's third-party-verified $CO_2$ emissions rate associated with the electricity delivered to customers in 201 6 as compared to the national average for electric utilities:

| | Amount (pounds of $CO_2$ per MWh) |
|---|---|
| U.S. Average [1] | 1,123 |
| Pacific Gas and Electric Company [2] | 294 |

(1) Source: EPA eGRID.
(2) Since the Utility purchases a portion of its electricity from the wholesale market, the Utility is not able to track some of its delivered electricity back to a specific generator. Therefore, there is some unavoidable uncertainty in the Utility's emissions rate.

***Air Emissions Data for Utility-Owne d Generation***

In addition to GHG emissions data provided above, the table below sets forth information about the air emissions from the Utility's owned generation facilities. The Utility's owned generation (primarily nuclear and hydroelectric facilities) comprised approximately one-half of the Utility's delivered electricity in 201 6 . PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

| | 2016 | 2015 |
|---|---|---|
| Total NOx Emissions (tons) | 141 | 160 |
| NOx Emissions Rate (pounds/MWh) | 0.01 | 0.01 |
| Total $SO_2$ | 13 | 17 |
| $SO_2$ | 0.001 | 0.001 |

***Water Quality***

In 2014, the EPA issued final regulations to implement the requirements of the federal Clean Water Act that require cooling water intake structures at electric power plants, such as the nuclear generation facilities at Diablo Canyon, to reflect the best tech nology available to minimize adverse environmental impacts. Various industry and environmental groups have challenged the federal regulations in proceedings pending in the U.S. Court of Appeals for the Second Circuit. California's once-through cooling po licy discussed below is considered to be at least as stringent as the new federal regulations. Therefore, California's implementation process for the state policy will likely continue without any significant change.

At the state level, in 2010 , the Calif ornia Water Board adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The policy also provided for an alternative compliance approach for nuclear plants if certain criteria were met. As required by the policy , the California Water Board appointed a committee to evaluate the feasibility and cost of using alternative techno logies to achieve compliance at Diablo Canyon. The committee's consultant submitted its final report to the California Water Board in September 2014 . The report addressed feasibility, costs and timeframes to install alternative technologies at Diablo Can yon, such as cooling towers.

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon 's two nuclear power reactor units at the expiration of their current operating licenses in 2024 and 2025 . As a result o f the planned retirement, the California Water Board will no longer need to address alternative compliance measures for Diablo Canyon. A s required under the p olicy, the Utility paid an annual interim mitigation fee beginning in 2017, which it will continu e to pay until operations cease in 2025 .

Additionally, t he Utility expects that its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility, the Central Coast Board and the California Attorney General's Office regarding the thermal component of the plant's once-through cooling discharge. (For more information, see "Diablo Canyon Nuclear Power Plant" in Item 3. Legal Proceedings below.)

***Nuclear Fuel Disposal***

Under the Nuclear Waste Policy Act of 1982, the DOE and electric utilities with commercial nuclear power plants were authorized to enter into contracts under which the DOE would be required to dispose of the utilities' spent nuclear fuel and high-level radioactive waste by January 1998, in exchange for fees paid by the utilities' customers. The DOE has been unable to meet its contractual obligation with the Utility to dispose of nuclear waste from the Utility's two nuclear generating units at Diablo Canyon and the retired nuclear facility at Humbol dt Bay. As a result, the Utility constructed interim dry cask storage facilities to store its spent fuel onsite at Diablo Canyon and at Humboldt Bay until the DOE fulfills its contractual obligation to take possession of the spent fuel. The Utility and o ther nuclear power plant owners sued the DOE to recover the costs that they incurred to construct interim storage facilities for spent nuclear fuel.

In September 2012, the U.S. Department of Justice ("DOJ") and the Utility executed a settlement agreement that awarded the Utility $266 million for spent fuel storage costs incurred through December 31, 2010. The settlement agreement also provided a claims process by which the Utility submits annual requ ests for reimbursement of its ongoing spent fuel storage costs. Through 2017, the Utility has been awarded an additional $114 million through these annual submissions , including $15 million for costs incurred between June 1, 2015 and May 31, 2016. The cl aim for the period June 1, 2016 through May 31, 2017, totaled approximately $29 million and is currently under review by the DOE. These proceeds are being refunded to customers through rates. A new settlement agreement, for costs through 2019 was execute d in March 2017. Considerable uncertainty continues to exist regarding when and whether the DOE will meet its contractual obligation to the Utility and other nuclear power plant owners to dispose of spent fuel.

## ITEM 1A. RISK FACTORS

PG&E Corporation's and the Utility's financial results can be affected by many factors, including estimates and assumptions used in the critical accounting policies described in MD&A, that can cause their actual financial results to differ materially from historical results or from anticipated future financial results. The following discussion of key risk factors should be considered in evaluating an investment in PG&E Corporation and the Utility and should be read in conjunction with MD&A and the Consolidated Financial Statements and related Notes in Part II, Item 8, "Financial Statements and Supplementary Data" of this Form 10-K. Any of these factors, in whole or in part, could materially affect PG&E Corporation's and the Utility's business, financial condition, results of operations, liquidity, cash flows, and stock price.

### Risks Related to 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 impact of the Northern California wildfires. PG&E Corporation and the Utility also expect to be the subject of additional lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions.***

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 impact of the multiple wildfires that 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, beginning on October 8, 2017 (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 California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44.

The Utility incurred $219 million in costs for service restoration and repair to the Utility's facilities (including $97 million in capital expenditures) through December 31, 2017 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 fires are being investigated 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. The CPUC's SED also 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 investigation is complete.

As of January 31, 2018, the Utility had submitted 22 electric incident reports to the CPUC associated with the Northern California wildfires where Cal Fire 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 cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, 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. (See "The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation or the Utility are subject, could significantly expand the potential liabilities from such litigation and materially negatively affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows" below.) In addition to such claims for property damage, 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.

Give n the preliminary stages of 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 material. PG&E Corporation and the Utility currently are unable to re asonably estimate the amount of 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 Departm ent 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 $1 1.79 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 o f 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 Util ity 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 c ause 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 l osses 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 f or 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 estimated in respect of 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.

PG&E Corporation and t he Utility also are the subj ect of a still increasing number of lawsuits that have been filed against PG&E Corporation and the Utility in Sonoma, Napa and San Francisco Counties’ Superior Courts, several of which seek to be certified as class actions. 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 ad dition, 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. PG&E Corporation and the Utility expect to be the subject o f 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 $800 million. 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.

In addition, it could take a number of years before the Utility’s final liability is known and the Utility could apply for cost recovery. 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. Further, SB 819, introduced in the California Senate in January 2018, if it becomes law, would prohibit utilities from recovering costs in excess of insurance resulting from damages c aused by such utilities’ facilities, if the CPUC determines that the utility did not reasonably construct, maintain, manage, control, or operate the facilities. PG&E Corporation and the Utility have considered certain actions that might be taken to attemp t 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 likel ihood 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. (See “If the Utility is unable to recover all or a sign ificant portion of its excess costs in connection with the Northern California wildfires and the Butte fire through ratemaking mechanisms, PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows could be m aterially affected” below.)

Losses in connection with the wildfires would likely require PG&E Corporation and the Utility to seek financing, which may not be available on terms acceptable to PG&E Corporation or the Utility, or at all, when required. (See “Risks Related to Liquidity and Capital Requirements” below.)

As of December 31, 2017, neither PG&E Corporation nor the Utility has accrued a liability with respect to the Northern California wildfires. If PG&E Corporation and the Utility were to determi ne that it is both probable that a loss has occurred and the amount of loss can be reasonably estimated, a liability would be recorded consistent with applicable accounting principles and as described in Note 13 of the Notes to the Consolidated Financial S tatements in Item 8. As noted above, to the extent that such determination is made and a liability is accrued with respect to the Northern California wildfires, the amount of such liability accrual may be substantial. To the extent not offset by insurance recoveries determined to be similarly probable and estimable, the liability would reduce the balance sheet equity of PG&E Corporation and the Utility, which could adversely impact the Utility's ability to maintain its CPUC-authorized capital structure of 5 2% equity and 48% debt and preferred stock, and which could also adversely impact PG&E Corporation's and the Utility's credit ratings and their ability to declare and pay dividends, efficiently raise capital, comply with financial covenants, and meet finan cial obligations. (See "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" below.)

Uncertainties relating to and market percept ion of these matters and the disclosure of findings regarding these matters over time, also could continue or increase volatility in the market for PG&E Corporation's common stock and other securities, and for the securities of the Utility, and materially affect the price of such securities.

***PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by the ultimate amount of third-party liability that the Utility incurs in connect ion 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 commer cial 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.

In connection with the Butte fire, complaints have been filed against t he Utility, currently involving approximately 3,770 individual plaintiffs representing approximately 2,030 households and their insurance companies. Plaintiffs seek to recover damages and other costs, principally based on the doctrine of inverse condemnati on and negligence theory of liability. Plaintiffs also seek punitive damages. The number of individual complaints and plaintiffs may still increase in the future , because the statute of limitations for property damages in connection with the Butte fire h as 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 seeking to recover $87 milli on for its costs incurred in connection with the Butte fire , and in May 2017, the OES indicated that it intends to bring a claim against the Utility that the OES estimated in the approximate amount of $190 million. Also, in June 2017, the County of Calave ras indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $85 million.

In connection with th is 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 were 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 probabl e that it will incur a loss of at least $1.1 billion , increased from the $750 million previously estimated as of December 31, 2016 in connection with the Butte fire. W hile this amount includes the Utility's assumptions about fire suppression costs (includ ing its assessment of the Cal Fire loss), it does not include any significant portion of the estimated claims from the OES and the County of Calaveras. The Utility still does not have sufficient information to reasonably estimate the probable loss it may have for these additional claims. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flo ws. (See Note 13 to the Consolidated Financial Statements in Item 8.)

***If the Utility is unable to recover all or a significant portion of its e xcess costs in connection with the Northern California wildfires and the Butte Fire through ratemaking mechanis ms, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.***

Through December 31, 2017, the amounts accrued in connection with claims relating to the Butte fire have exceeded the Utility's liability insurance coverage. While the Utility filed an application with the CPUC requesting approval to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of wildfire costs that have not otherwise been recovered through insurance or other mechanisms, the Utility cannot predict the outcome of this proceeding. (See " Regulatory Matters – Application to Establish a Wildfire Expense Memorandum Account" in Item 7. MD&A.)

In addition, there can be no assurance that the Utility will be allowed to recover costs recorded in WEMA, if approved, in the future. While the CPUC previously approved WEMA tracking accounts for San Diego Gas & Electric Company in 2010, in December 2017, the CPUC den ied 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.

Additionally, SB 819 introduced in the California Senate in January 2018, i f it becomes law, would prohibit utilities' recover y of costs in excess of insurance resulting from damages caused by such utilities' facilities, if the CPUC determines that the U tility did not reasonably construct, maintain, manage, control, or operate the facilities.

PG&E Corporation and the Utility hav e considered certain actions that might be taken to attempt to address liquidity needs of the business in such circumstances, but the inability to recover all or a significant portion of costs in excess of insurance through increases in rates and by collec ting 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 effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

***The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation or the Utility are subject, could significantly expand the potential liabilities from such litigation and materially affect PG&E Corporation 's and the Utility 's financial condition, results of operations, liquidity and cash flows.***

California law includes a doctrine of inverse condemnation that is routinely invoked in California for wildfire damages. Inverse condemnation imposes strict liability (including liability for attorneys' fees) for damages as a result of the design, construction and maintenance of utility facilities, including utilities' electric transmission lines. Courts have imposed liability under the doctrine of inv erse 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 benefitted from such unde rtaking , and based on the assumption that utilities have the ability to recover these costs from their customers. Plaintiffs have asserted the doctrine of inverse condemnation in lawsuits related to the Northern California and Butte fires, and it is possib le that plaintiffs could be successful in convincing courts to apply this doctrine in these or other litigations. For example, o n June 22, 2017, the Superior Court for the County of Sacramento found that the doctrine of inverse condemnation applies to the Utility with respect to the Butte fire. Although the Utility has filed a renewed motion for a legal determination of inverse condemnation liability , there can be no assurance that the Utility will be successful in its arguments that the doctrine of invers e condemnation does not apply in the Butte fire or other litigation against PG&E Corporation or the Utility.

Furthermore, a court 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. Although the imposition of liability is premised on the assumption that utilities have the ability to automatically recover these costs from their customers, there can be no guar antee that the CPUC would authorize cost recovery whether or not a previous court decision imposes liability on a utility under the doctrine of inverse condemnation. I n December 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.

I f PG&E Corporation or the Utility were to be found liable for damage under the doctrine of inverse condemnation, but is unable to secure a cost recovery decision from the CPUC to pay for such costs through increases in rates , the financial condition, results of operations, liquidity and cash flows of PG&E Corporation and the Utility would be materially affected by potential losses resulting from the impact of the Northern California wildf ires. (See " PG&E Corporation and the Utility also expect to be the subject of additional lawsuits and could be the subject of additional investigations, citations, fines or enforcement actions" and "PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows could be materially affected by the ultimate amount of third-party liability that the Utility incurs in connection with the Butte fire" above.)

**Risks Related to the Outcome of Other Enforcement Matters, Investigations, and Regulatory Proceedings**

***The Utility is subject to extensive regulations and the risk of enforcement proceedings in connection with such regulations, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected by the outcomes of the CPUC's investigative enforcement proceedings against the Utility, other known enforcement matters, and other ongoing state and federal investigations and requests for information. The Utility could incur material costs and fines in connection with compliance with penalties from closed investigations or enforcement actions or in connection with future investigations, citations, audits, or enforcement actions.***

The Utility is subject to extensive regulations, including federal, state and local energy, environmental and other laws and regulations, and the risk of enforcement proceedings in connection with such regulations. The Utility could incur material charges, including fines and other penalties, in connection with the ex parte OII, safety culture OII, and the CPUC's SED investigations, including the SED's investigations of the Yuba City incident, which arose from a residential structure fire in Yuba City, California, in January 2017, that resulted in the collapse of a house and injuries to two persons inside the house, or other current and future investigations. The SED could launch investigations at any time on any issue it deems appropriate.

The SED has discretion whether to issue a penalty for each violation, but if it 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. While it is uncertain how the CPUC will calculate the number of violations or the penalty for any violations, such fines or penalties could be significant and materially affect PG&E Corporation's and the Utility's liquidity and results of operations. (See Note 13 to the Consolidated Financial Statements in Item 8.)

The Utility also is a target of a number of investigations. 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 also is unable to predict the outcome of, or costs and expenses associate with, pending investigations, including whether any charges will be brought against the Utility.

If these investigations result in enforcement action against the Utility, the Utility could incur additional fines or penalties and, in the event of a judgment against the Utility, suffer further ongoing negative consequences. For example, on April 9, 2015, the CPUC issued a decision in its investigative enforcement proceedings against the Utility to impose total penalties of $1.6 billion on the Utility after determining that the Utility had committed numerous violations of laws and regulations related to its natural gas transmission operations (the "San Bruno Penalty Decision"). The San Bruno Penalty Decision requires the SED to review the Utility's gas transmission operations (including the Utility's compliance with the remedies ordered by the San Bruno Penalty Decision) and to perform annual audits of the Utility's record-keeping practices for a minimum of ten years. The SED could impose fines on the Utility or require the Utility to incur unrecoverable costs, or both, based on the outcome of these future audits. Furthermore, a negative outcome in any of these investigations, or future enforcement actions, could negatively affect the outcome of future ratemaking and regulatory proceedings to which the Utility may be subject; for example, by enabling parties to challenge the Utility's request to recover costs that the parties allege are somehow related to the Utility's violations. (See also "PG&E Corporation's and the Utility's future financial results could be materially affected by the conviction of the Utility in the federal criminal proceeding and by the debarment proceeding" below.)

The Utility could be subject to additional regulatory or governmental enforcement action in the future with respect to compliance with federal, state or local laws, regulations or orders that could result in additional fines, penalties or customer refunds, including those regarding renewable energy and resource adequacy requirements; customer billing; customer service; affiliate transactions; vegetation management; design, construction, operating and maintenance practices; safety and inspection practices; compliance with CPUC general orders or other applicable CPUC decisions or regulations; federal electric reliability standards; and environmental compliance. For example, despite the Utility's system-wide survey of its transmission pipelines, carried out 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 SED could impose fines on the Utility in the future based on the Utility's failure to continuously survey its system and remove encroachments. CPUC staff could also impose penalties on the Utility in the future in accordance with its authority under the gas and electric safety citation programs. The amount of such fines, penalties, or customer refunds could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

***PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected in the event of non-compliance with the terms of probation and by the outcome of the debarment proceedin g.***

On August 9, 2016, the jury in the federal criminal trial against the Utility in the United States District Court for the Northern District of California, in San Francisco, found the Utility guilty on one count of obstructing a federal agency proceedin g and five counts of violations of pipeline integrity management regulations of the Natural Gas Pipeline Safety Act. On January 26, 2017, the court issued a judgment of conviction against the Utility. The court sentenced the Utility to a five- year corpor ate probation period, oversight by a third-party monitor for a period of five years, with the ability to apply for early termination after three years , a fine of $3 million to be paid to the federal government, certain advertising requirements, and communi ty service.

The probation includes a requirement that the Utility not commit any local, state, or federal crimes during the probation period. As part of the probation, the Utility has retained a third-party monitor at the Utility's expense. The goal of the monitor is to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of its gas and electric operations, and to maintain effective ethics, compliance and safety related incentive programs on a Utility-wide basis.

The Utility could incur material costs and additional penalties , not recoverable through rates, in the event of non-compliance with the terms of its probation and in connection with the monitorship (including but not limited to costs resulting from recomme ndations of the monitor).

Since 2015, the Utility has also been the subject of a DOI inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs , citing the San Bruno e xplosion , and indicating, as the basis for the inquiry, alleged poor record-keeping, poor identification and evaluation of threats to gas lines and obstruction of the NTSB's investigation. On December 21, 2016, the Utility and the DOI entered into an inter im administrative agreement that reflects the DOI's determination that the Utility remains eligible to contract with federal government agencies while the DOI determines whether any further action is necessary to protect the federal government's business i nterests. If the DOI determines that the Utility's compliance and ethics program is not generally effective in preventing and detecting criminal conduct, the Utility may be required to enter into an amended administrative agreement and implement remedial a nd other measures, such as a requirement that the Utility's natural gas operations and/or compliance and eth ics programs be supervised by one or more independent third- party monitor (s) .

The Utility's conviction and the outcome of probation and the debarme nt proceeding could harm the Utility's relationships with regulators, legislators, communities, business partners, or other constituencies and make it more difficult to recruit qualified personnel and senior management. Further, they could negatively affe ct the outcome of future ratemaking and regulatory proceedings, for example, by enabling parties to argue that the Utility should not be allowed to recover costs that the parties allege are somehow related to the criminal charges on which the Utility was f ound guilty. They could also result in increased regulatory or legislative scrutiny with respect to various aspects of how the Utility's business is conducted or organized. (See "Enforcement and Litigation Matters " in Item 7. MD&A.)

***PG&E Corporation's and the Utility's financial results primarily depend on the outcomes of regulatory and ratemaking proceedings and the Utility's ability to manage its operating expenses and capital expenditures so that it is able to earn its authorized rate of return in a timely manner.***

As a regulated entity, the Utility's rates are set by the CPUC or the FERC on a prospective basis and are generally designed to allow the Utility to collect sufficient revenues to recover reasonable costs of providing service, including a return on its capital investments. PG&E Corporation's and the Utility's financial results could be materially affected if the CPUC or the FERC does not authorize sufficient revenues for the Utility to safely and reliably serve its customers and earn its authorized ROE. The outcome of the Utility's ratemaking proceedings can be affected by many factors, including the level of opposition by intervening parties; potential rate impacts; increasing levels of regulatory review; changes in the political, regula tory, or legislative environments; and the opinions of the Utility's regulators, consumer and other stakeholder organizations, and customers, about the Utility's ability to provide safe, reliable, and affordable electric and gas services. Further, the inc reasing amount of Reliability Must Run ( " RMR " ) electric generation in the CAISO could increase the Utility's costs of procuring capacity needed for reliable service to its customers .



In addition to the amount of authorized revenues, PG&E Corporation's an d the Utility's financial results could be materially affected if the Utility's actual costs to safely and reliably serve its customers differ from authorized or forecast costs. The Utility may incur additional costs for many reasons including changing ma rket circumstances, unanticipated events (such as storms, fires, accidents, or catastrophic or other events affecting the Utility's operations), or compliance with new state laws or policies. Although the Utility may be allowed to recover some or all of t he additional costs, there may be a substantial time lag between when the Utility incurs the costs and when the Utility is authorized to collect revenues to recover such costs. Alternatively, the CPUC or the FERC may disallow costs that they determine wer e not reasonably or prudently incurred by the Utility.

The Utility also is required to incur costs to comply with legislative and regulatory requirements and initiatives, such as those relating to the development of a state-wide electric vehicle charging infrastructure, the deployment of distributed energy resources, implementation of demand response and customer energy efficiency programs, energy storage and renewable energy targets, underground gas storage, and the construction of the California high-sp eed rail project. The Utility's ability to recover costs, including its investments, associated with these and other legislative and regulatory initiatives will, in large part, depend on the final form of legislative or regulatory requirements, and whethe r the associated ratemaking mechanisms can be timely adjusted to reflect a lower customer demand for the Utility's electricity and natural gas services .

***PG&E Corporation's and the Utility's financial results depend upon the Utility's continuing ability t o recover "pass-through" costs, including electricity and natural gas procurement costs, from customers in a timely manner. The CPUC may disallow procurement costs for a variety of reasons. In addition, the Utility's ability to recover these costs could be affected by the loss of Utility customers and decreased new customer growth , if the CPUC fails to adjust the Utility's rates to reflect such events.***

The Utility meets customer demand for electricity from a variety of sources, including electricity generated from the Utility's own generation facilities, electricity provided by third parties under power purchase agreements, and purchases on the wholesale electricity market. The Utility must manage these sources using the commercial and CPUC regulatory principles of "least cost dispatch" and prudent administration of power purchase agreements in compliance with its CPUC-approved long-term procurement plan. The CPUC could disallow procurement costs incurred by the Utility if the CPUC determines that the Utility did not comply with these principles or if the Utility did not comply with its procurement plan.

Further, the contractual prices for electricity under the Utility's current or future power purchase agreements could become uneconomic in the future for a variety of reasons, including developments in alternative energy technology, increased self-generation by customers, an increase in distributed generation, and lower customer demand due to adverse economic conditions or the loss of the Utility's customers to other retail providers. In particular, the Utility will incur additional costs to procure renewable energy to meet the higher targets established by California SB 350 that became effective on January 1, 2016. Despite the CPUC's current approval of the contracts, the CPUC could disallow contract costs in the future if it determines that the terms of such contracts, including price, do not meet the CPUC reasonableness standard.

The Utility's ability to recover the costs it incurs in the wholesale electricity market may be affected by whether the CAISO wholesale electricity market continues to function effectively. Although market mechanisms are designed to limit excessive prices, these market mechanisms could fail, or the related systems and software on which the market mechanisms rely may not perform as intended which could result in excessive market prices. The CPUC could prohibit the Utility from passing through the higher costs of electricity to customers. For example, during the 2000 and 2001 energy crisis, the market mechanism flaws in California's then-newly established wholesale electricity market led to dramatically high market prices for electricity that the Utility was unable to recover through customer rates, ultimately causing the Utility to file a petition for reorganization under Chapter 11 of the U.S. Bankruptcy Code.

Further, PG&E Corporation's and the Utility's financial results could be affected by the loss of Utility customers and decreasing bundled load that occurs through municipalization of the Utility's facilities, an increase in the number of CCAs who provide electricity to their residents, and an increase in the number of consumers who become direct access customers of alternative generation providers. (See "Competition in the Electricity Industry" in Item 1.) As the number of bundled customers (i.e., those customers who receive electricity and distribution service from the Utility) declines, the rates for remaining customers could increase as the Utility would have a smaller customer base from which to recover certain procurement costs. Although the Utility is permitted to collect non-bypassable charges for above market generation-related costs incurred on behalf of former customers, the charges may not be sufficient for the Utility to fully recover these costs. In addition, the Utility's ability to collect non-bypassable charges has been, and may continue to be, challenged by certain customer groups. Furthermore, if the former customers return to receiving electricity supply from the Utility, the Utility could incur costs to meet their electricity needs that it may not be able to timely recover through rates or that it may not be able to recover at all.

In addition, increasing levels of self-generation of electricity by customers (primarily solar installations) and the use of customer NEM, which allows self-generating customers to receive bill credits for surplus power at the full retail rate, puts upward rate pressure on remaining customers. New rules and rates became effective for new NEM customers of the Utility in December 2016. New NEM customers are required to pay an interconnection fee, comply with time of use rates, and are required to pay certain non-bypassable charges to help fund some of the cos ts of low income, energy efficiency, and other programs that other customers pay. Remaining customers may incur significantly higher bills due to an increase in customers seeking alternative energy providers . The CPUC has indicated that it intends to revi sit these rules in 2019.

A confluence of technology-related cost declines and sustained federal or state subsidies could make a combination of distributed generation and energy storage a viable, cost-effective alternative to the Utility's bundled electric service which could further threaten the Utility's ability to recover its generation, transmission, and distribution investments. If the number of the Utility's customers decreases or grows at a slower rate than anticipated, the Utility's level of author ized capital investment could decline as well, leading to a slower growth in rate base and earnings. Reduced energy demand or significantly slowed growth in demand due to customer migration to other energy providers, adoption of energy efficient technolog y, conservation, increasing levels of distributed generation and self-generation, unless substantially offset through regulatory cost allocations, could materially affect PG&E Corporation's and the Utility's business, financial condition, results of operat ions, liquidity, and cash flows.

The CPUC has begun to implement rate reform to allow residential electric rates to more closely reflect the utilities' actual costs of providing service and decrease cross -subsidization among customer classes. Many aspe cts of rate reform are not yet finalized, including time-of-use rates and whether the utilities can impose a fixed charge on certain customers.

Further, c hanges in commodity prices also may have an adverse effect on the Utility's ability to timely recov er its operating costs and earn its authorized ROE. Although the Utility generally recovers its electricity and natural gas procurement costs from customers as "pass-through" costs, a significant and sustained rise in commodity prices could create overall rate pressures that make it more difficult for the Utility to recover its costs that are not categorized as "pass-through" costs. To relieve some of this upward rate pressure, the CPUC could authorize lower revenues than the Utility requested or disallow full cost recovery.

If the Utility is unable to recover a material portion of its procurement costs and/or if the CPUC fails to adjust the Utility's rates to reflect the impact of changing loads, the wide deployment of distributed generation, and the d evelopment of new electricity generation and energy storage technologies, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected .

**Risks Related to Liquidity and Capital Re quirements**

***The outcome or market perception of the investigations and litigation in connection with the Northern California wildfires, and the outcome or market perception of other litigation and enforcement matters, could reduce or eliminate PG&E Corpora tion's and the Utility's access to the capital markets and other sources of financing, which could have a material adverse effect on PG&E Corporation and the Utility.***

PG&E Corporation's and the Utility's liquidity is dependent on many factors, including a ccess to the capital markets and availability under their revolving credit facilities and commercial paper program s . PG&E Corporation's and the Utility's ability to access the capital markets, t he ability t o borrow under their loan financing arrangements, including their revolving credit facilities, and the terms and rates of future financings, as well as the credit ratings of PG&E Corporation and the Utility and their respective debt facilities, could be materially affected by the outcome or market percep tion of the matters discussed in this 2017 Form 10-K under "Northern California Wildfires" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 . Liabilities that could be incurred as a result of the Northern California wildfires could adversely affect their ability to comply with the covenants in their financing arrangements, which could adversely affect the ability to borrow under the applicable facility or program.

Access by PG&E Corporation to the equity capital markets is also critical to maintaining the Utility's CPUC-authorized capital structure. PG&E Corporation contributes equity to t he Utility as needed to maintain the Utility's CPUC-author ized capital structure. In the fiscal year ended December 31, 2017, PG&E Corporation issued $ 416 million in common stock and made equity contributions of $ 455 million to the Utility . PG&E Corporatio n forecasts it will need a material am ount of equity in future years, including to support the Utility's capital expenditures. PG&E Corporation may also seek to issue additional equity to fund unrecoverable operating expenses and to pay claims, losses, fin es and penalties that may be required by the outcome of enforcement matters and litigation, including in connection with the Northern California wildfires, and the outcome of the related CPUC and Cal Fire investigations.

If either PG&E Corporation or the Utility is unable to access the capital markets or to borrow under their respective loan financing arrangements or commercial paper program s , PG&E Corporation and the Utility's financial condition, results of operations, liquidity, and cash flows, could be materially affected.

***PG&E Corporation's and the Utility's ability to meet their debt service and other financial obligations and their ability to pay dividends depend on the Utility's earnings and cash flows. In addition, in December 2017, the Boards of Directors suspended dividends on PG&E Corporation's common stock and the Utility's preferred stock, as a result of which the price of PG&E Corporation's common stock and the ability of PG&E Corporation and the Utility to raise equity capital could be ad versely affected.***

PG&E Corporation is a holding company with no revenue generating operations of its own. The Utility must use its resources to satisfy its own obligations, including the Utility's obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends , unless suspended, and meet its obligations to employees and creditors, before it can distribute cash to PG&E Corporation . Under the CPUC's rules applicable to utility holding companies, the Utility's dividend policy must be established by the Utility's Board of Directors as though the Utility were a stand-alone utility company and PG&E Corporation's Board of Directors must give "first priority" to the Utility's capital requirements, as determined to be necessary and prudent to meet the Utility's obligation to serve or to operate the Utility in a prudent and efficient manner. The CPUC has interpreted this "first priority" obl igation to include the requirement that PG&E Corp oration "infuse the Utility with all types of capital necessary for the Utility to fulfill its obligation to serve . " In addition, before the Utility can pay common stock dividends to PG&E Corp oration , the U tility must maintain its authorized capital structure with an average 52% equity component.

If the Utility were required to pay a material amount of fines or incur material unrecoverable costs in connection with the Northern California wildfires , the Butt e fire , the pending CPUC investigations, the terms of probation or monitorship, or other liabilities or enforcement matters, it would require incremental equity contributions from PG&E Corporation to restore its capital structure. PG&E Corp oration common s tock issuances used to fund such equity contributions could materially dilute earnings per share. (See "Liquidity and Financ ial Resources" in Item 7. MD&A ). Further, if PG&E Corp oration were required to infuse the Utility with significant capital or if the Utility w ere unable to distribute cash to PG&E Corporation , or both, PG&E Corporation may be unable to pay principal and interest on its outstanding debt, pay its common stock dividend or meet other obligations.

In December 2017, the Boards of Directors of PG&E Corporation and the Utility suspended dividends on common stock of PG&E Corporation and preferred stock of the Utility due to uncertainty related to the causes and potential liabilities associated with the Northern California wildfires. The suspens ion of dividends could continue to materially affect the price of PG&E Corporation's common stock and adversely affect the ability of PG&E Corporation to raise additional equity capital. There can be no assurances as to when, if at all, the Board of Direct ors of PG&E Corporation and the Utility will determine to re-instate quarterly cash dividends on PG&E Corporation's common stock or the Utility's preferred stock.

***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 costs related to rights-of-way and 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 o n 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, 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. On December 21, 2017, Moody's Investor Services and on December 22, 2017, S tandard & P oor's Global Ratings, each placed all of the ratings of PG&E Corporation and the Utility under review for downgrade , and Standard & Poor's Globa l Ratings additionally lowered its ratings on the Utility's preferred stock . If PG&E Corporation's or the Utility's credit ratings were to be downgraded or the ratings on the Utility's preferred stock are further downgraded, in particular to below investm ent 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 collater al 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 affec ting 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 Item 3. Legal Proceedings and Note 13 of the Notes to the Consolidated Financial Statements in Item 8 . 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 Corporati on'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.

**Risks Related to Operatio ns and Information Technology**

***The Utility's electricity and natural gas operations are inherently hazardous and involve significant risks which, if they materialize, can adversely affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.***

The Utility owns and operates extensive electricity and natural gas facilities, including two nuclear generation units and an extensive hydroelectric generating system . (See "Electric Utility Operations" and "Nat ural Gas Utility Operations" in Item 1. Business.) The Utility's ability to earn its authorized ROE depends on its ability to efficiently maintain, operate, and protect its facilities, and provide electricity and natural gas services safely and reliably. The Utility undertakes substantial capital investment projects to construct, replace, and improve its electricity and natural gas facilities. In addition, the Utility is obligated to decommission its electricity generation facilities at the end of their useful operating lives , and the CPUC approved retirement of Diablo Canyon by 2024 and 2025 . The Utility's ability to safely and reliably operate, maintain, construct and decommission its facilities is subject to numerous risks, many of which are beyond th e Utility's control, including those that arise from:

- the breakdown or failure of equipment, electric transmission or distribution lines, or natural gas transmission and distribution pipelines, that can cause explosions, fires, or other catastrophic eve nts;
- an overpressure event occurring on natural gas facilities due to equipment failure, incorrect operating procedures or failure to follow correct operating procedures, or welding or fabrication-related defects, that results in the failure of downstream transmission pipelines or distribution assets and uncontained natural gas flow;
- the failure to maintain adequate capacity to meet customer demand on the gas system that results in customer curtailments, controlled/uncontrolled gas outages, gas surges back into homes, serious personal injury or loss of life;
- a prolonged statewide electric al black-out that results in damage to the Utility's equipment or damage to property owned by customers or other third parties;
- the failure to fully identify, evaluate, and control workplace hazards that result in serious injury or loss of life for emplo yees or the public, environmental damage, or reputational damage;
- the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act;
- the failure of a large dam or other major hydroelectric facility, o r the failure of one or more levees that protect land on which the Utility's assets are built;
- the failure to take expeditious or sufficient action to mitigate operating conditions, facilities, or equipment, that the Utility has identified, or reasonably should have identified, as unsafe, which failure then leads to a catastrophic event (such as a wild land fire or natural gas explosion) ;
- inadequate emergency preparedness plans and the failure to respond effectively to a catastrophic event that can lead to public or employee harm or extended outages;
- operator or other human error;
- an ineffective records management program that results in the failure to construct, operate and maintain a utility system safely and prudently;
- construction performed by thir d parties that damage s the Utility's underground or overhead facilities, including, for example, ground excavations or "dig-ins" that damage the Utility's underground pipelines;
- the release of hazardous or toxic substances into the air, water, or soil, in cluding, for example, gas leaks from natural gas storage facilities; flaking lead-based paint from the Utility's facilities, and leaking or spilled insulating fluid from electrical equipment; and
- attacks by third parties, including cyber-attacks, acts of terrorism, vandalism, or war.

The occurrence of any of these events could interrupt fuel supplies; affect demand for electricity or natural gas; cause unplanned outages or reduce generating output; damage the Utility's assets or operations; damage the assets or operations of third parties on which the Utility relies; damage property owned by customers or others; and cause personal injury or death. As a result, the Utility could incur costs to purchase replacement power, to repair assets and restore se rvice, and to compensate third parties.

Further, although the Utility often enters into agreements for third-party contractors to perform work, such as patrolling and inspection of facilities or the construction or demolition or facilities, the Utility may retain liability for the quality and completion of the contractor's work and can be subject to penalties or other enforcement action if the contractor violates applicable laws, rules, regulations, or orders. The Utility may also be subject to liability, penalties or other enforcement action as a result of personal injury or death caused by third-party contractor actions.

Insurance, equipment warranties, or other contractual indemnification requi rements may not be sufficient or effective to provide full or even partial recovery under all circumstances or against all hazards or liabilities to which the Utility may become subject. An uninsured loss could have a material effect on PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows.

***The Utility's insurance coverage may not be sufficient to cover losses caused by an operating failure or catastrophic events, including severe weather events, or m ay not be available at a reasonable cost, or available at all.***

The Utility has experienced increased costs and difficulties in obtaining insurance coverage for wildfires that could arise from the Utility's ordinary operations. PG&E Corporation, the Utilit y or its contractors and customers may experience coverage reductions and/or increased wildfire insurance costs in future years. No assurance can be given that future losses will not exceed the limits of the Utility's insurance coverage. Uninsured losses a nd increases in the cost of insurance may not be recoverable in customer rates. A loss which is not fully insured or cannot be recovered in customer rates could materially affect PG&E Corporation's and the Utility's financial condition, results of operatio ns, liquidity, and cash flows .

As a result of the potential application of a strict liability standard under the doctrine of inverse condemnation , recent losses recorded by insurance companies, the risk of increase of wildfires including as a result of t he ongoing drought, the Northern California wildfires, and the Butte fire, the Utility may not be able to obtain sufficient insurance coverage in the future at comparable cost and terms as the Utility's current insurance coverage, or at all. In addition, the Utility is unable to predict whether it would be allowed to recover in rates the increased costs of insurance or the costs of any uninsured losses.

Future insurance coverage may not be available at rates and on terms as favorable as the Utility's cur rent insurance coverage or may not be available at all. If the amount of insurance is insufficient or otherwise unavailable, or if the Utility is unable to recover in rates the costs of any uninsured losses, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

***The electric power industry is undergoing significant change driven by technological advancements and a decarbonized economy, which could materially impact the Utili ty's operations, financial condition, and results of operations.***

The electric power industry is 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 suppo rt California's climate change and GHG reduction objectives, which continue to be publicly supported by California policymakers notwithstanding a recent change in the federal approach to such matters. California utilities are experiencing increasing deplo yment by customers and third parties of DERs, such as on-site solar generation, energy storage, fuel cells, energy efficiency, and demand response technologies. This growth will require modernization of the electric distribution grid to, among other thing s, accommodate two-way flows of electricity, increase the grid's capacity, and interconnect DERs.

In order to enable the California clean energy economy, sustained investments are required in grid modernization, renewable integration projects, energy effi ciency programs, energy storage options, EV infrastructure and s tate infrastructure modernization (e.g. rail and water project s ).

To this end, the CPUC is conducting proceedings to: evaluate changes to the planning and operation of the electric distribution grid in order to prepare for higher penetration of DERs; consider future grid modernization and grid reinforcement investments; evaluate if traditional grid investments can be deferred by DERs, and if feasible, what, if any, compensation to utilities would be appropriate for enabling those investments; and clarify the role of the electric distribution grid operator. The CPUC has also recently opened proceedings regarding the creation of a shared database or statewide census of utility poles and conduits in California and increased access by communications providers to utility rights-of-way. This proceeding could require utilities to invest significant resources into inspecting poles and conduits, limit available capacity in existing rights-of-way, or impose other requirements on utilities facilities. The Utility is unable to predict the outcome of these proceedings.

In addition, the CPUC has held discussions on potential changes to California's electricity market. On May 19, 2017, California energy companies, along with other stakeholders, discussed customer choice and the future of the state's electricity industry at a CPUC "en banc" meeting. Specifically, the goal of the "en banc" was to frame a discussion on the trends that are driving change within California's electricity sector and overall clean-energy economy and to lay out elements of a path forward to ensure that California achieves its reliability, affordability, equity, and carbon reduction imperatives while recognizing the important role that technology and customer preferences will play in shaping this future. While the CPUC had indicated its intent to open a proceeding related to customer choice, the Utility is unable to predict whether that remains the CPUC's intent or the timing of any such proceeding.

The industry change, costs associated with complying with new regulatory developments and initiatives and with technological advancements, or the Utility's inability to successfully adapt to changes in the electric industry, could materially affect the Utility's operations, financial condition, and results of operations.

***A cyber incident, cyber security breach, severe natural event or physical attack on the Utility's operational networks and information technology systems could have a material effect on its business, financial condition, results of operations, liquidity, and cash flows.***

The Utility's electricity and natural gas systems rely on a complex, interconnected network of generation, transmission, distribution, control, and communication technologies, which can be damaged by natural events—such as severe weather or seismic events—and by malicious events, such as cyber and physical attacks. Private and public entities, such as the North American Electric Reliability Corporation, and U.S. Government Departments, including the Departments of Defense, Homeland Security and Energy, and the White House, have noted that cyber-attacks targeting utility systems are increasing in sophistication, magnitude, and frequency. The Utility's operational networks also may face new cyber security risks due to modernizing and interconnecting the existing infrastructure with new technologies and control systems. Any failure or decrease in the functionality of the Utility's operational networks could cause harm to the public or employees, significantly disrupt operations, negatively impact the Utility's ability to safely generate, transport, deliver and store energy and gas or otherwise operate in the most safe and efficient manner or at all, and damage the Utility's assets or operations or those of third parties.

The Utility also relies on complex information technology systems that allow it to create, collect, use, disclose, store and otherwise process sensitive information, including the Utility's financial information, customer energy usage and billing information, and personal information regarding customers, employees and their dependents, contractors, and other individuals. In addition, the Utility often relies on third-party vendors to host, maintain, modify, and update its systems, and to provide other services to the Utility or the Utility's customers. These third-party vendors could cease to exist, fail to establish adequate processes to protect the Utility's systems and information, or experience security incidents or inadequate security measures. Any incidents or disruptions in the Utility's information technology systems could impact the Utility's ability to track or collect revenues and to maintain effective internal controls over financial reporting.

The Utility and its third party vendors have been subject to, and will likely continue to be subject to attempts to gain unauthorized access to the Utility's information technology systems or confidential data (including information about customers and employees), or to disrupt the Utility's operations. None of these attempts or breaches has individually or in the aggregate resulted in a security incident with a material impact on PG&E Corporation's and the Utility's financial condition and results of operations. Despite implementation of security and control measures, there can be no assurance that the Utility will be able to prevent the unauthorized access to its operational networks, information technology systems or data, or the disruption of its operations. Such events could subject the Utility to significant expenses, claims by customers or third parties, government inquiries, penalties for violation of applicable privacy laws, investigations, and regulatory actions that could result in fines and penalties, loss of customers and harm to PG&E Corporation's and the Utility's reputation, any of which could have a material adverse effect on PG&E Corporation's and the Utility's financial condition and results of operations.

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

***The operation and decommissioning of the Utility's nucle ar generation facilities expose it to potentially significant liabilities and the Utility may not be able to fully recover its costs if regulatory requirements change or the plant ceases operations before the licenses expire.***

The operation of the Utilit y's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corpor ation's and the Utility's financial condition, results of operations, liquidity, and cash flows . In addition, the Utility may be required under federal law to pay up to $255 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

On January 11, 2018, the CPUC approved the retirement of Diablo Canyon un its by 2024 and 2025. However, the Utility continues to face public concern about the safety of nuclear generation and nuclear fuel. Some of these nuclear opposition groups regularly file petitions at the NRC and in other forums challenging the actions o f the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possi ble that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation. As a result, operations at the Utility's two nuclear generation units at Diablo Canyon could cease before the ir respective license s expire in 2024 and 2025. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge could have a material effect on PG&E Corporation and the Utility's financial condition, results of operations, liquidity, and cash flows.

In addition, in order to retain highly skilled personnel necessary to safely operate Diablo Canyon during the remaining years of operations, the Utility will incur costs in connection with (i) an employe e retention program to ensure adequate staffing levels at Diablo Canyon, and (ii) an employee retraining and development program, to facilitate redeployment of a portion of Diablo Canyon personnel to the decommissioning project and elsewhere in the company . In its January 11, 2018 decision, the CPUC authorized rate recovery up to $211.3 million (compared with the $352.1 million requested by the Utility) for an employee retention program , but there can be no assurance that the Utility will be successful in retaining highly skilled personnel under such program .

The Utility has incurred, and may continue to incur, substantial costs to comply with NRC regulations and orders. (See "Regulatory Environment" in Item 1. Business.) If the Utility were unable to re cover these costs, PG&E Corporation's and the Utility's financial results could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon's two nuclear generation units befor e their respective licenses expire in 2024 and 2025. At December 31, 2017, the Utility's unrecovered investment in Diablo Canyon was $1.7 billion.

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

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

***The Utility purchases its nuclear fuel assemblies from a sole source, Westinghouse. If Westinghouse experiences business disruptions as a result of Chapter 11 proceedings or its pending acquisition by Brookfield, the Utility could experience disruptions in nuclear fuel supply, and delays in connection with its Diablo Canyon outages and refuelings.***

The Utility purchases its nuclear fuel assemblies for Diablo Canyon from a sole source, Westinghouse. The Utility also stores nuclear fuel inventory at the Westinghouse fuel fabrication facility. In addition, Westinghouse provides the Utility with Diablo Canyon outage support services, nuclear fuel analysis, original equipment manufacturer engineering and parts support. On March 29, 2017, Westinghouse filed for Chapter 11 protection in the United States Bankruptcy Court, Southern District of New York. On January 4, 2018, Westinghouse announced that it has agreed to be acquired by Brookfield Business Partners L.P. Westinghouse also indicated that its acquisition by Brookfield is expected to close in the third quarter of 2018, subject to Bankruptcy Court approval and customary closing conditions including, among others, regulatory approvals. In the event that Westinghouse experiences business disruptions in its nuclear fuel business as a result of bankruptcy proceedings, its pending acquisition by Brookfield, or otherwise, the Utility could experience issues with its nuclear fuel supply and delays in connection with Diablo Canyon refueling outages.

Diablo Canyon's Unit 2 refueling outage will occur in the first quarter of 2018 and the required fuel for that outage has been delivered. The next Unit 1 refueling outage is expected to occur in the first quarter of 2019 and the fuel for that outage has not yet been fabricated. If Westinghouse were to fail to deliver nuclear fuel or provide outage support to the Utility, the Utility's operation of Diablo Canyon would be adversely affected. PG&E Corporation and the Utility also could experience additional costs, including decreased electricity market revenues, in the event that one or both Diablo Canyon units are unable to operate. There can be no assurance that any such additional costs would be recoverable in the rates the Utility is permitted to recover from its customers. Furthermore, the Utility currently is not able to estimate the nature or amount of additional costs and expenses that it might incur in connection with the uncertainties surrounding Westinghouse but such costs and expenses could be material.

***For certain critical technologies, products and services, the Utility relies on a limited number of suppliers and, in some cases, sole suppliers. In the event these suppliers are unable to perform, the Utility could experience delays and disruptions in its operations while it transitions to alternative plans or suppliers.***

The Utility relies on a limited number of sole source suppliers for certain of its technologies, products and services. Although the Utility has long-term agreements with such suppliers, if the suppliers are unable to deliver these technologies, products or services, the Utility could experience delays and disruptions while it implements alternative plans and makes arrangements with acceptable substitute suppliers. As a result, the Utility's business, financial condition, and results of operations could be significantly affected. As an example, the Utility relies on Silver Spring Networks, Inc. and Aclara Technologies LLC as suppliers of proprietary SmartMeter™ devices and software, and of managed services, utilized in its advanced metering system that collects electric and natural gas usage data from customers. If these suppliers encounter performance difficulties or are unable to supply these devices or maintain and update their software, or provide other services to maintain these systems, the Utility's metering, billing, and electric network operations could be impacted and disrupted.

**Risks Related to Environmental Factors**

***Severe weather conditions, extended drought and shifting climate patterns could materially affect PG&E Corporation's and the Utility's business, financial condition, results of operations, liquidity, and cash flows.***

Extreme weather, extended drought and shifting climate patterns have intensified the challenges associated with wildfire management in California. Environmental extremes, such as drought conditions followed by periods of wet weather, can drive additional vegetation growth ( which then fuel any fires ) and influence both the likelihood and severity of extraordinary wildfire events. In California, over the past five years, inconsistent and extreme precipitation, coupled with more hot summer days, have increased the wildfire risk and made wildfire outbreaks increasingly difficult to manage. In particular, the risk posed by wildfires has increased in the Utility's service area (the Utility has approximately 82,000 distribution overhead circuit miles and 18,000 transmission overhead circuit miles) as a result of an extended period of drought, bark beetle infestations in the California forest and wildfire fuel increases due to record rainfall following the drought, among other environmental factors. Other contributing factors include local land use policies and historical forestry management practices. The combined effects of extreme weather and climate change also impact this risk.

Severe weather events , including wildfires and other fires, storms, tornadoes, floods, drought, earthquakes, tsunamis, pandemics, solar events, electromagnetic events, or other natural disasters such as wildfires, could result in severe business disruptions, prolonged power outages, property damage, injuries or loss of life, significant decreases in revenues and earnings, and/or significant additional costs to PG&E Corporation and the Utility. Any such event could have a material effect on PG&E Corporation's and the Utility's business , financial condition, results of operations, liquidity, and cash flows . If the Utility is unable to recover its wildfire costs, due to the reasons described in the risk factors related to the Northern California fires, Butte fire, the doctrine of inverse condemnation, and insurance limitations above, or for other reasons, its financial condition, results of operations, liquidity, and cash flows could be materially affected.

Further, the Utility has been studying the potential effects of climate change (increased temperatures, changing precipitation patterns, rising sea levels) on the Utility's operations and is developing contingency plans to adapt to those events and conditions that the Utility believes are most significant. Scientists project that climate change will increase electricity demand due to more extreme, persistent and hot weather. As a result, the Utility's hydroelectric generation could change and the Utility would need to consider managing or acquiring additional generation. If the Utility increases its reliance on conventional generation resources to replace hydroelectric generation and to meet increased customer demand, it may become more costly for the Utility to comply with GHG emissions limits. In addition, flooding caused by rising sea levels could damage the Utility's facilities, including generation and electric transmission and distribution assets. The Utility could incur substantial costs to repair or replace facilities, restore service, or compensate customers and other third parties for damages or injuries. The Utility anticipates that the increased costs would be recovered through rates, but as rate pressures increase, the likelihood of disallowance or non-recovery may increase.

Events or conditions caused by climate change could have a greater impact on the Utility's operations than the Utility's studies suggest and could result in lower revenues or increased expenses, or both. If the CPUC fails to adjust the Utility's rates to reflect the impact of events or conditions caused by climate change, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

***The Utility's operations are subject to extensive environmental laws and changes in or liabilities under these laws could adversely affect PG&E Corporation's and the Utility's financial results.***

The Utility's operations are subject to extensive federal, state, and local environmental laws, regulations, and orders, relating to air quality, water quality and usage, remediation of hazardous wastes, and the protection and conservation of natural resources and wildlife. The Utility incurs significant capital, operating, and other costs associated with compliance with these environmental statutes, rules, and regulations. The Utility has been in the past, and may be in the future, required to pay for environmental remediation costs at sites where it is identified as a potentially responsible party under federal and state environmental laws. Although the Utility has recorded liabilities for known environmental obligations, these costs can be difficult to estimate due to uncertainties about the extent of contamination, remediation alternatives, the applicable remediation levels, and the financial ability of other potentially responsible parties. (For more information, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

Environmental remediation costs could increase in the future as a result of new legislation, the current trend toward more stringent standards, and stricter and more expansive application of existing environmental regulations. Failure to comply with these laws and regulations, or failure to comply with the terms of licenses or permits issued by environmental or regulatory agencies, could expose the Utility to claims by third parties or the imposition of civil or criminal fines or other sanctions.

The CPUC has authorized the Utility to recover its environmental remediation costs for certain sites through various ratemaking mechanisms. One of these mechanisms allows the Utility rate recovery for 90% of its hazardous substance remediation costs for certain approved sites without a reasonableness review. The CPUC may discontinue or change these ratemaking mechanisms in the future or the Utility may incur environmental costs that exceed amounts the CPUC has authorized the Utility to recover in rates.

Some of the Utility's environmental costs, such as the remediation costs associated with the Hinkley natural gas compressor site, are not recoverable through rates or insurance. (See "Environmental Regulation" in Item 1. and Note 13 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's costs to remediate groundwater contamination near the Hinkley natural gas compressor site and to abate the effects of the contamination have had, and may continue to have, a material effect on PG&E Corporation's and the Utility's financial results. Their financial results also can be materially affected by changes in estimated costs and by the extent to which actual remediation costs differ from recorded liabilities.

***State climate policy requires reductions in greenhouse gases of 40% by 2030 and 80% by 2050. Various proposals for addressing these reductions have the potential to reduce natural gas usage and increase natural gas costs. The future recovery of the increased costs associated with compliance is uncertain.***

The CARB is the state's primary regulator for GHG emission reduction programs. Natural gas providers have been subject to compliance with CARB's Cap-and-Trade Program since 2015, and natural gas end-use customers have an increasing exposure to carbon costs under the Program through 2030 when the full cost will be reflected in customer bills. CARB's Scoping Plan also proposes various methods of reducing GHG emissions from natural gas. These include more aggressive energy efficiency programs to reduce natural gas end use, increased renewable portfolio standards generation in the electric sector reducing noncore gas load, and replacement of natural gas appliances with electric appliances, leading to further reduced demand. These natural gas load reductions may be partially offset by CARB's proposals to deploy natural gas to replace wood fuel in home heating and diesel in transportation applications. CARB also proposes a displacement of some conventional natural gas with above- market renewable natural gas. The combination of reduced load and increased costs could result in higher natural gas customer bills and a potential mandate to deliver renewable natural gas could lead to cost recovery risk.

**Other Risk Factors**

***The Utility may be required to incur substantial costs in order to obtain or renew licenses and permits needed to operate the Utility's business and the Utility may be subject to fines and penalties for failure to comply or obtain license renewal.***

The Utility must c omply with the terms of various governmental permits, authorizations, and licenses, including those issued by the FERC for the continued operation of the Utility's hydroelectric generation facilities, and those issued by environmental and other federal, st ate and local governmental agencies. Many of the Utility's capital investment projects, and some maintenance activities, often require the Utility to obtain land use, construction, environmental, or other governmental permits. These permits, authorizatio ns, and licenses may be difficult to obtain on a timely basis, causing work delays. Further, existing permits and licenses could be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed whe n they were issued. In addition, the Utility often seeks periodic renewal of a license or permit, such as a waste discharge permit or a FERC operating license for a hydroelectric generation facility.

If a license or permit is not renewed for a particul ar facility and the Utility is required to cease operations at that facility, the Utility could incur an impairment charge or other costs.  Before renewing a permit or license, the issuing agency may impose additional requirements that may increase the Uti lity's compliance costs.  In particular, in connection with a license renewal for one or more of the Utility's hydroelectric generation facilities or assets, the FERC may impose new license conditions that could, among other things, require increased expen ditures or result in reduced electricity output and/or capacity at the facility.

In addition, local governments may attempt to assert jurisdiction over various utility operations by requiring permits or other approvals that the Utility has no t been previously required to obtain.

The Utility may incur penalties and sanctions for failure to comply with the terms and conditions of licenses and permits which could have a material effect on PG&E Corporation's and the Utility's financial conditio n, results of operations, and cash flows. If the Utility cannot obtain, renew, or comply with necessary governmental permits, authorizations, licenses, ordinances, or other requirements, or if the Utility cannot recover the increase in associated complian ce and other costs in a timely manner, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

***Poor investment performance or other factors could require PG&E Corporation an d the Utility to make significant unplanned contributions to its pension plan, other postretirement benefits plans, and nuclear decommissioning trusts.***

PG&E Corporation and the Utility provide defined benefit pension plans and other postretirement benefit s for eligible employees and retirees. The Utility also maintains three trusts for the purposes of providing funds to decommission its nuclear facilities. The performance of the debt and equity markets affects the value of plan assets and trust assets. A decline in the market value may increase the funding requirements for these plans and trusts. The cost of providing pension and other postretirement benefits is also affected by other factors, including interest rates used to measure the required minimu m funding levels, the rate of return on plan assets, employee demographics, discount rates used in determining future benefit obligations, rates of increase in health care costs, future government regulation, and prior contributions to the plans. Similarl y, funding requirements for the nuclear decommissioning trusts are affected by the rates of return on trust assets, changes in the laws or regulations regarding nuclear decommissioning or decommissioning funding requirements as well as changes in assumptio ns or forecasts related to decommissioning dates, technology and the cost of labor, materials and equipment. (See Note 2: Summary of Significant Accounting Policies of the Notes to the Consolidated Financial Statements in Item 8.) If the Utility is requi red to make significant unplanned contributions to fund the pension and postretirement plans or if actual nuclear decommissioning costs exceed the amount of nuclear decommissioning trust funds and the Utility is unable to recover the contributions or addit ional costs in rates, PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows could be materially affected.

***The Utility's success depends on the availability of the services of a qualified workforce and its ability to maintain satisfactory collective bargaining agreements which cover a substantial number of employees. PG&E Corporation's and the Utility's results may suffer if the Utility is unable to attract and retain qualified personnel and senior management talent, or if prolonged labor disruptions occur.***

The Utility’s workforce is aging and many employees are or will become eligible to retire within the next few years. Although the Utility has undertaken efforts to recruit and train new field service personnel, the Utility may be faced with a shortage of experienced and qualified personnel. The majority of the Utility’s employees are covered by collective bargaining agreements with three unions. Labor disruptions could occur depending on the outcome of negotiations to renew the terms of these agreements with the unions or if tentative new agreements are not ratified by their members. In addition, some of the remaining non-represented Utility employees could join one of these unions in the future.

PG&E Corporation and the Utility also may face challenges in attracting and retaining senior management talent especially if they are unable to restore the reputational harm generated by the negative publicity stemming from the ongoing enforcement proceed ings. Any such occurrences could negatively impact PG&E Corporation's and the Utility's financial condition and results of operations.

***The Utility's business activities are concentrated in one region, as a result of which, its future performance may be a ffected by events and factors unique to California.***

The Utility's business act ivities are concentrated in Northern California. As a result, the Utility's future performance may be affected by events and e conomic factors unique to California or by regional regulation or legislation , for example the doctrine of inverse condemnation . (See " The doctrine of inverse condemnation, if applied by courts in litigation to which PG&E Corporation and the Utility are s ubject, could significantly expand the potential liabilities from such litigation and materially affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity and cash flows " above.)

**ITEM 1B. UNRESOLVED STAFF COMMENTS**

None.

**ITEM 2. PROPERTIES**

The Utility owns or has obtained the right to occupy and/or use real property comprising the Utility's electricity and natural gas distribution facilities, natural gas gathering facilities and generation facilities, and natural gas and electricity transmission facilities, which are described in Item 1. Business, under “Electric Utility Operations” and “Natural Gas Utility Operations.” The Utility occupies or uses real property that it does not own primarily through various leases, easements, rights-of-way, permits, or licenses from private landowners or governmental authorities. In total, the Utility occupies 11 million square feet of real property, including 9 million square feet owned by the Utility. The Utility's corporate headquarters comprises approximately 1.7 million square feet located in several Utility-owned buildings in San Francisco, California.

PG&E Corporation also leases approximately 42,000 square feet of office space from a third party in San Francisco, California. This lease will expire in 2022.

The Utility currently owns approximately 160,000 acres of land, including approximately 132,000 acres of watershed lands. In 2002 the Utility agreed to implement its “Land Conservation Commitment” (“LCC”) to permanently preserve the six “beneficial public values” on all the watershed lands through conservation easements or equivalent protections, as well as to make approximately 70,000 acres of the watershed lands available for donation to qualified organizations. The six “beneficial public values” being preserved by the LCC include: natural habitat of fish, wildlife, and plants; open space; outdoor recreation by the general public; sustainable forestry; agricultural uses; and historic values. The Utility’s goal is to implement all the transactions needed to implement the LCC by the end of 2022, subject to securing all required regulatory approvals.

**ITEM 3. 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 material lawsuits and proceedings, see “Enforcement and Litigation Matters” in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 and in Item 7. MD&A.

**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 President 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 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. Other parties’ responsive testimony is due February 16, 2018, and the Utility’s rebuttal is due February 23, 2018. On January 29, 2018, the CPUC modified the procedural schedule to allow more time for parties to better identify areas of agreement to reduce the number of issues that may require hearings.

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**

The Utility's Diablo Canyon power plant employs a "once-through" cooling water system that is regulated under a Clean Water Act permit issued by the Central Coast Board. This permit allows the Diablo Canyon power plant to discharge the cooling water at a temperature no more than 22 degrees above the temperature of the ambient receiving water, and requires that the beneficial uses of the water be protected. The beneficial uses of water in this region include industrial water supply, marine and wildlife habitat, shellfish harvesting, and preservation of rare and endangered species. In January 2000, the Central Coast Board issued a proposed draft cease and desist order alleging that, although the temperature limit has never been exceeded, the Utility's Diablo Canyon power plant's discharge was not protective of beneficial uses.

In October 2000, the Utility and the Central Coast Board reached a tentative settlement under which the Central Coast Board agreed to find that the Utility's discharge of cooling water from the Diablo Canyon power plant protects beneficial uses and that the intake technology reflects the best technology available, as defined in the federal Clean Water Act. As part of the tentative settlement, the Utility agreed to take measures to preserve certain acreage north of the plant and to fund approximately $6 million in environmental projects and future environmental monitoring related to coastal resources. On March 21, 2003, the Central Coast Board voted to accept the settlement agreement. On June 17, 2003, the settlement agreement was executed by the Utility, the Central Coast Board and the California Attorney General's Office. A condition to the effectiveness of the settlement agreement was that the Central Coast Board renew Diablo Canyon's permit.

However, at its July 10, 2003 meeting, the Central Coast Board did not renew the permit and continued the permit renewal hearing indefinitely. Several Central Coast Board members indicated that they no longer supported the settlement agreement, and the Central Coast Board requested a team of independent scientists to develop additional information on possible mitigation measures for Central Coast Board staff. In 2005, the Central Coast Board reviewed the scientists' draft report recommending several such mitigation measures, but no action was taken.

In 2010, the California Water Board adopted a policy on once-through cooling that generally requires the installation of cooling towers or other significant measures to reduce the impact on marine life from existing power generation facilities in California by at least 85%. The policy also provided for an alternative compliance approach for nuclear plants if certain criteria were met. As required by the policy, the California Water Board appointed a committee to evaluate the feasibility and cost of using alternative technologies to achieve compliance at Diablo Canyon. The committee's consultant submitted its final report to the California Water Board in September 2014. The report addressed feasibility, costs and timeframes to install alternative technologies at Diablo Canyon, such as cooling towers.

On January 11, 2018, the CPUC approved the retirement of Diablo Canyon Unit 1 by 2024 and Unit 2 by 2025. As a result of the planned retirement, the California Water Board will no longer need to address alternative compliance measures for Diablo Canyon. As required under the policy, the Utility paid an annual interim mitigation fee beginning in 2017, which it will continue to pay until operations cease in 2025. Additionally, the Utility expects that its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility and the Central Coast Board regarding the thermal component of the plant's once-through cooling discharge.

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

## ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

## EXECUTIVE OFFICERS OF THE REGISTRANTS

The following individuals serve as executive officers [1] of PG&E Corporation and/or the Utility, as of February 9, 2018. Except as otherwise noted, all positions have been held at Pacific Gas and Electric Company.

| Name | Age | Positions Held Over Last Five Years | Time in Position |
|---|---|---|---|
| Geisha J. Williams | 56 | Chief Executive Officer and President, PG&E Corporation | March 1, 2017 to present |

| | | | |
|---|---|---|---|
| | | President, Electric | September 15, 2015 to February 28, 2017 |
| | | President, Electric Operations | August 17, 2015 to September 15, 2015 |
| | | Executive Vice President, Electric Operations | June 1, 2011 to August 16, 2015 |
| Nickolas Stavropoulos | 59 | President and Chief Operating Officer | March 1, 2017 to present |
| | | President, Gas | September 15, 2015 to February 28, 2017 |
| | | President, Gas Operations | August 17, 2015 to September 15, 2015 |
| | | Executive Vice President, Gas Operations | June 13, 2011 to August 16, 2015 |
| Jason P. Wells | 40 | Senior Vice President and Chief Financial Officer, PG&E Corporation | January 1, 2016 to present |
| | | Vice President, Business Finance | August 1, 2013 to December 31, 2015 |
| | | Vice President, Finance | October 1, 2011 to July 31, 2013 |
| John R. Simon | 53 | Executive Vice President and General Counsel, PG&E Corporation | March 1, 2017 to present |
| | | Executive Vice President, Corporate Services and Human Resources, PG&E Corporation | August 17, 2015 to February 28, 2017 |
| | | Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company | April 16, 2007 to August 16, 2015 |
| Karen A. Austin | 56 | Senior Vice President and Chief Information Officer | June 1, 2011 to present |
| Loraine M. Giammona | 50 | Senior Vice President and Chief Customer Officer | September 18, 2014 to present |
| | | Vice President, Customer Service | January 23, 2012 to September 17, 2014 |
| Patrick M. Hogan | 54 | Senior Vice President, Electric Operations | February 1, 2017 to present |
| | | Senior Vice President, Electric Transmission and Distribution | March 1, 2016 to January 31, 2017 |
| | | Vice President, Electric Strategy and Asset Management | September 8, 2015 to February 29, 2016 |
| | | Vice President, Electric Operations, Asset Management | November 18, 2013 to September 7, 2015 |
| | | Senior Vice President, Transmission and Distribution Engineering and Design, BC Hydro | October 2011 to November 2013 |
| Julie M. Kane | 59 | Senior Vice President, Chief Ethics and Compliance Officer, and Deputy General Counsel, PG&E Corporation and Pacific Gas and Electric Company | March 21, 2017 to present |
| | | Senior Vice President and Chief Ethics and Compliance Officer, PG&E Corporation and Pacific Gas and Electric Company | May 18, 2015 to March 20, 2017 |

| | | | |
|---|---|---|---|
| | | Vice President, General Counsel and Compliance Officer, North America, Avon Products, Inc. | September 30, 2013 to March 31, 2015 |
| | | Vice President, Ethics and Compliance, Novartis Corporation | January 1, 2010 to August 31, 2015 |
| Steven E. Malnight | 45 | Senior Vice President, Strategy and Policy, PG&E Corporation and Pacific Gas and Electric Company | March 1, 2017 to present |
| | | Senior Vice President, Regulatory Affairs | September 18, 2014 to February 28, 2017 |
| | | Vice President, Customer Energy Solutions | May 15, 2011 to September 17, 2014 |
| Dinyar B. Mistry | 56 | Senior Vice President, Human Resources and Chief Diversity Officer, PG&E Corporation and Pacific Gas and Electric Company | February 1, 2017 to present |
| | | Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company | June 1, 2016 to January 31, 2017 |
| | | Senior Vice President, Human Resources, Chief Financial Officer, and Controller | March 1, 2016 to May 31, 2016 |
| | | Senior Vice President, Human Resources and Controller, PG&E Corporation | March 1, 2016 to May 31, 2016 |
| | | Vice President, Chief Financial Officer, and Controller | October 1, 2011 to February 28, 2016 |
| | | Vice President and Controller, PG&E Corporation | March 8, 2010 to February 28, 2016 |
| Jesus Soto, Jr. | 50 | Senior Vice President, Gas Operations | September 8, 2015 to present |
| | | Senior Vice President, Engineering, Construction and Operations | September 16, 2013 to September 8, 2015 |
| | | Senior Vice President, Gas Transmission Operations | May 29, 2012 to September 15, 2013 |
| Fong Wan | 56 | Senior Vice President, Energy Policy and Procurement, Pacific Gas and Electric Company | September 8, 2015 to present |
| | | Senior Vice President, Energy Procurement | October 1, 2008 to September 8, 2015 |
| David S. Thomason | 42 | Vice President, Chief Financial Officer, and Controller, Pacific Gas and Electric Company | June 1, 2016 to present |
| | | Vice President and Controller, PG&E Corporation | June 1, 2016 to present |
| | | Senior Director, Financial Forecasting and Analysis | March 2, 2015 to May 31, 2016 |
| | | Senior Director, Corporate Accounting | March 2, 2014 to March 1, 2015 |
| | | Senior Director, Financial Forecasting and Analysis | September 1, 2012 to March 1, 2014 |

[(1)] Ms. Williams, Mr. Stavropoulos , Mr. Wells, Mr. Simon , Ms. Kane, Mr. Malnight and Mr. Mistry are executive officers of both PG&E Corporation and the Utility.  All other listed officers are executive officers of the Utility only.

## PART II

### ITEM 5. MARKET FOR REGISTRAN T'S COMMON EQUITY, RELATED SHARE HOLDER MATTERS AND ISSUER PURCHASES OF EQUIT Y SECURITIES

As of February 1 , 201 8 , there were 53,878 holders of record of PG&E Corporation common stock. PG&E Corporation common stock is listed on the New York Stock Exchange and is traded under the symbol "PCG" . The high and low closing prices of PG&E Corporation common stock for each quarter of the two most recent fiscal y ears are set forth in the table entitled "Quarterly Consolidated Financial Data (Unaudited)" which appears after the Notes to the Consolidated Financial Statements in Item 8. Shares of common stock of the Utility are wholly owned by PG&E Corporation. Information about the frequency and amount of dividends on common stock declared by PG&E Corporation and the Utility for the two most recent fiscal years and information about the restrictions upon the payment of dividends on their common stock appears in "Li quidity and Financial Resources – Dividends" in Item 7 . MD&A and in PG&E Corporation's Consolidated Statements of Equity, the Utility's Consolidated Statements of S har eholders' Equity, and in Note 5 of the Notes to the Consolidated Financial Statements in Item 8 .

***Sales of Unregistered Equity Securities***

PG&E Corporation made equity contributions to the Utility totaling $50 million d uring the quarter ended December 31, 2017 . PG&E Corporation did not make any sales of unregistered equity securities during 2017 in reliance on an exempt ion from registration under the Securities Act of 1933, as amended.

***Issuer Purchases of Equity Securities***

During the quarter ended December 31, 2017 , PG&E Corporation did not redeem or repurchase any shares of common stock outstanding. PG&E Corporation does not have any preferred stock outstanding. Also, during the quarter ended December 31, 2017, the Utility did not redeem or repurchase any shares of its various series of preferred st ock outstanding.

**ITEM 6. SELECTED FINANCIAL DATA**

| (in millions, except per share amounts) | 2017 | 2016 | 2015 | 2014 | 2013 |
|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 17,135 | $ 17,666 | $ 16,833 | $ 17,090 | $ 15,598 |
| Operating income | 2,956 | 2,177 | 1,508 | 2,450 | 1,762 |
| Net income | 1,660 | 1,407 | 888 | 1,450 | 828 |
| Net earnings per common share, basic (1) | 3.21 | 2.79 | 1.81 | 3.07 | 1.83 |
| Net earnings per common share, diluted | 3.21 | 2.78 | 1.79 | 3.06 | 1.83 |
| Dividends declared per common share (2) | 1.55 | 1.93 | 1.82 | 1.82 | 1.82 |
| **At Year-End** | | | | | |
| Common stock price per share | $ 44.83 | $ 60.77 | $ 53.19 | $ 53.24 | $ 40.28 |
| Total assets | 68,012 | 68,598 | 63,234 | 60,228 | 55,693 |
| Long-term debt (excluding current portion) | 17,753 | 16,220 | 15,925 | 15,151 | 12,805 |
| Capital lease obligations (excluding current portion) (3) | 18 | 31 | 49 | 69 | 90 |
| **Pacific Gas and Electric Company** | | | | | |
| **For the Year** | | | | | |
| Operating revenues | $ 17,138 | $ 17,667 | $ 16,833 | $ 17,088 | $ 15,593 |
| Operating income | 2,900 | 2,181 | 1,511 | 2,452 | 1,790 |
| Income available for common stock | 1,677 | 1,388 | 848 | 1,419 | 852 |
| **At Year-End** | | | | | |
| Total assets | 67,884 | 68,374 | 63,037 | 59,964 | 55,137 |
| Long-term debt (excluding current portion) | 17,403 | 15,872 | 15,577 | 14,799 | 12,805 |
| Capital lease obligations (excluding current portion) (3) | 18 | 31 | 49 | 69 | 90 |

(1) See “Overview – Summary of Changes in Net Income and Earnings per Share ” in Item 7. MD&A.

(2) Information about the frequency and amount of dividends and restrictions on the payment of dividends is set forth in “Liquidity and Financial Resources – Dividends” in Item 7 . MD&A and in PG& E Corporation’s Consolidated Statements of Equity, the Utility’s Consolidated Statements of Shareholders’ Equity, and Note 5 in Item 8.

(3) The capital lease obligations amounts are included in noncurrent liabilities – other in PG&E Corporation’s and the Utility’s Consolidated Balance Sheets.

## ITEM 7. 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 nat ural gas to customers.

The Utility's base revenue requirements are set by the CPUC in its GRC and GT&S rate case and by the FERC in its TO rate cases based on forecast costs. Differences between forecast costs and actual costs can occur for numerous rea sons, including the volume of work required and the impact of market forces on the cost of labor and materials. Differences in costs can also arise from changes in laws and regulations at both the state and federal level. Generally, differences between a ctual costs and forecast costs affect the Utility's ability to earn its authorized return (referred to as "Utility Revenues and Costs that Impacted Earnings" in Results of Operations below). However, for certain operating costs, such as costs associated w ith pension and other employee benefits, the Utility is authorized to track the difference between actual amounts and forecast amounts and recover or refund the difference through rates (referred to as "Utility Revenues and Costs that did not Impact Earnin gs" in Results of Operations below). The Utility also collects revenue requirements to recover certain costs that the CPUC has authorized the Utility to pass on to customers, such as the costs to procure electricity or natural gas for its customers. Ther efore, although these costs can fluctuate, they generally do not impact net income (referred to as "Utility Revenues and Costs that did not Impact Earnings" in Results of Operations below). See "Ratemaking Mechanisms" in Item 1 for further discussion.

This is a combined report of PG&E Corporation and the Utility, and includes separate Consolidated Financial Statements for each of these two entities. This combined MD&A should be read in conjunction with the Consolidated Financial Statements and the Note s to the Consolidated Financial Statements included in Item 8.

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 California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44.

The fires are being investigated 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 way that they progressed. The CPUC's SED is also conducting investigations to as sess 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 investigation is complete.

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

### Tax Cuts and Jobs Act of 201 7

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly refer red to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35 percent to 21 percent beginning on January 1, 2018 and elim inated bonus depreciation for utilities.

The Tax Act also required PG&E Corporation and the Utility to re-measure existing deferred income tax assets and liabilities to reflect the lower federal tax rate. During the three months and year ended December 31, 2017, PG&E Corporation , on a consolidated basis, recorded a one-time provisional tax expense of $147 million to reflect the transitional impacts of the Tax Act. Of this amount, $83 million is attributable to the re-measurement of PG&E Corporation's n et deferred tax asset comprised primarily of net operating loss carry - forwards and compensation-related items. The remaining $64 million is related to the re-measurement of the Utility's deferred taxes not reflected in authorized revenue requirements, such as disallowed plant. The Utility also recorded a provisional $5. 7 billion re-measurement of its deferred tax balances ( related to flow-through and normalized timing differences for plant-related items ) which was offset by a change from a net deferred income tax regulatory asset t o a net regulatory liability. The net deferred income tax regulatory liability will be refunded to customers over the regulatory lives of the related assets. The final transition impacts of the Tax Act may materi ally vary from the above recorded amounts due to, among other things, future regulatory decisions from the CPUC that could differ from the Utility's determination of how the impacts of the Tax Act are allocated between customers and shareholders.

As a r esult of the Tax Act, the Utility intends to file by the end of March 2018 (i) revised revenue requirements and rate base in its 201 7 GRC (for years 2018 and 2019) and 2015 GT&S rate case (for 2018) as well as a proposed implementation plan in connection t hereto, and (ii) revised revenue requirement and rate base forecast in its 2019 GT&S rate case. The Utility is unable to predict the timing and outcome of the CPUC decision i n connection with such filing s .

On an aggregate basis, t he Utility anticipates an annual reduction to revenue requirements of approximately $500 million starting in 2018 , and incremental increase s to rate base of approximately $500 million in 2018 and $800 million in 2019 as a result of the Tax Act . The estimated benefit to customer s is driven by the lower federal income tax rate applied to future earnings and the return of excess deferred income taxes. These benefits are partially offset by earnings on higher rate base and lower tax benefits from flow-through items.

In addition to this reduction in future revenue requirements, the Tax Act is expected to accelerate when PG&E Corporation resumes paying federal taxes , primarily due to the elimination of bonus depreciation ; although future taxes are expected to be lower due to the lower federal tax rate. PG&E Corporation now expects to pay federal taxes starting in 2020 , although that timing would be impacted by any significant changes to future results of operations . Add itionally, because the revenue reduction is expected to precede the reduction in federal income tax payments, PG&E Corporation's and the Utility's operating cash flows will be negatively impacted resulting in additional financing needs.

**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 the three months and twelve months ended December 31, 2017 compared to the three months and twelve months ended December 31, 2016 and a summary reconciliation of the key drivers of PG&E Corporation's earnings from operations and EPS based on earnings from operations for th e three months and twelve months ended December 31, 2017 compared to the three months and twelve months ended December 31, 2016 . " Earnings from operations " is a non-GAAP financial measure and is calculated as income availab le 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 C orporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal b udgeting 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 . E arnings from operations are not a substitute or alternative for GAAP measures such as income av ailable for common shareholders and may not be comparable to similarly titled measures used by other companies.

| | Three Months Ended December 31, | | | | Year Ended December 31, | | | |
|---|---|---|---|---|---|---|---|---|
| (in millions, | Earnings | | Earnings per Common Share (Diluted) | | Earnings | | Earnings per Common Share (Diluted) | |
| except per share amounts) | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 | 2017 | 2016 |
| **PG&E Corporation's Earnings on a GAAP basis** | **$ 114** | **$ 692** | **$ 0.22** | **$ 1.36** | **$ 1,646** | **$ 1,393** | **$ 3.21** | **$ 2.78** |
| Items Impacting Comparability: (1) | | | | | | | | |
| Tax Cuts and Jobs Act transition impact (2) | 147 | - | 0.29 | - | 147 | - | 0.29 | - |
| Northern California wildfire-related costs (3) | 49 | - | 0.09 | - | 49 | - | 0.09 | - |
| Butte fire-related costs, net of insurance (4) | 9 | 27 | 0.02 | 0.05 | 36 | 137 | 0.07 | 0.27 |
| Pipeline related expenses (5) | 7 | 20 | 0.01 | 0.04 | 52 | 67 | 0.10 | 0.13 |
| Legal and regulatory related expenses (6) | 1 | 11 | - | 0.02 | 6 | 43 | 0.01 | 0.09 |
| Fines and penalties (7) | - | 101 | - | 0.20 | 47 | 307 | 0.09 | 0.61 |
| Diablo Canyon settlement-related disallowance (8) | - | - | - | - | 32 | - | 0.06 | - |
| GT&S revenue timing impact (9) | - | (193) | - | (0.38) | (88) | (193) | (0.17) | (0.38) |
| Net benefit from derivative litigation settlement (10) | - | - | - | - | (38) | - | (0.07) | - |
| GT&S capital disallowance | - | 17 | - | 0.04 | - | 130 | - | 0.26 |
| **PG&E Corporation's Earnings from Operations (11)** | **$ 327** | **$ 675** | **$ 0.63** | **$ 1.33** | **$ 1,889** | **$ 1,884** | **$ 3.68** | **$ 3.76** |

All amounts presented in the table above are tax adjusted at PG&E Corporatio n's statutory tax rate of 40.75 percent, exce pt as indicated below.

(1) "Items impacting comparability" represent items that management does not consider part of the normal cou rse of operations and affect comparability of financial results between periods.

(2) PG&E Corporation , on a consolidated basis, incurred a one-time charge of $147 million during the three and twelve months ended December 31, 2017, as a result of the T ax Cuts and Jobs Act, which was signed into law on December 22, 2017. The Utility's charge of $64 million was related to deferred taxes not reflected in the authorized revenue requirements, such as deferred tax assets associated with disallowed plant , and PG&E Corporation's charge of $83 million was primarily related to net operating loss carryforwards a nd compensation-related deferred tax assets .

(3) The Utility incu rred costs of $82 million (before the tax impact of $33 million) during the three and twelve months ended December 31, 2017, associated with the Northern California wildfires. This includes charges of $64 million (before the tax impact of $26 million) for the three and twelve months ended December 31, 2017, for the reinstatement of liability insurance coverage and $18 million (before the tax impact of $7 million) during the three and twelve months ended December 31, 2017, for legal and other expenses.

(4) The Utility incurred costs, net of insurance, of $15 million (before the tax impact of $6 million) and $60 million (before the tax impact of $24 million) during the three and twelve months ended December 31, 2017, respectively, associated with the Butte fire. This includes accrued charges of $350 million (before the tax impact of $143 million) during the twelve months ended December 31, 2017, related to estimated third-party claims. The Utility also incurred charges of $15 million (before the tax impact of $6 million) and $60 million (before the tax impact of $ 25 million) during the three and twelve months ended December 31, 2017, respectively, for legal costs . These costs were partially offset by $350 million (before the tax impact of $14 3 million) rec orded during the twelve months ended December 31, 2017, for expected insurance recoveries.

(5) The Utility incurred costs of $ 12 million (before the tax impact of $ 5 million ) and $ 89 million (before the tax impact of $3 7 million ) during the three and twe lve months ended December 31, 2017, respectively, for pipeline related expenses incurred in connection with the multi-year effort to identify and remove encroachments from transmission pipeline rights-of-way.

(6) The Utility incurred costs of $2 million (before the tax impact of $1 million ) and $10 million (before the tax impact of $4 million ) during the three and twelve months ended December 31, 2017, respectively, for legal and regulatory related expenses incurred in connection with various enforcement, regulatory, and litigation activities regarding natural gas matters and regulatory communications.

(7) The Utility incurred costs of $71 million (before the tax impact of $24 million) during the twelve months ended December 31, 2017, for fines and penalti es. This includes costs of $32 million (before the tax impact of $13 million) during the twelve months ended December 31, 2017, associated with safety-related cost disallowances imposed by the CPUC in its April 9, 2015 San Bruno Penalty Decision in the ga s transmission pipeline investigations. The Utility also recorded $15 million (before the tax impact of $6 million) during the twelve months ended December 31, 2017, for penalty imposed by the CPUC in its final phase two decision of the 2015 GT&S rate cas e for prohibited ex parte communications. In addition, the Utility recorded $24 million (before the tax impact of $5 million) during the twelve months ended December 31, 2017, in connection with the PD in the OII into Compliance with Ex Parte Communicatio n Rules.

(8) Consistent with the CPUC decision adopted on January 11, 2018 in connection with the retirement of the Diablo Canyon Power Plant , the Utility recorded a disallowance of $47 million (before the tax impact of $15 million) during the twelve mo nths ended December 31, 2017, comprised of cancelled projects of $24 million (before the tax impact of $6 million) and disallowed license renewal costs of $23 million (befor e the tax impact of $9 million) .

(9) As a result of the CPUC's final phase tw o dec ision in the 2015 GT&S rate case, during the twelve months ended December 31, 2017, the Utility recorded revenues of $150 million (before the tax impact of $62 million) in exce ss of the 2017 authorized revenue requirement, which includes the final componen t of under-collected revenues retroactive to January 1, 2015.

(10) PG&E Corporation recorded proceeds from insu rance, net of plaintiff payments, of $65 million (before the tax impact of $27 million) during the twelve months ended December 31, 2017, associated with the settlement agreement in connection with the shareholder derivative litigation that was approved by the court on July 18, 2017. This includes $90 million (before the tax impact of $37 million) for insurance recoveries partially offset b y $25 million (before the tax impact of $10 million) for plaintiff legal fees paid in connection with the settlement during the twelve months ended December 31 , 2017 .

(11) "Earnings from operations" is a non-GAAP financial measure.

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

| | Three Months Ended December 31, | | Twelve Months Ended December 31, | |
|---|---|---|---|---|
| (in millions, except per share amounts) | **Earnings** | **Earnings per Common Share (Diluted)** | **Earnings** | **Earnings per Common Share (Diluted)** |
| 2016 Earnings from Operations (1) | $ 675 | $ 1.33 | $ 1,884 | $ 3.76 |
| Timing of 2015 GT&S revenue impact (2) | (172) | (0.33) | - | - |
| Timing of taxes (3) | (90) | (0.18) | - | - |
| Impact of 2017 GRC decision (4) | (47) | (0.09) | (139) | (0.27) |
| Timing of operational spend (5) | (31) | (0.06) | - | - |
| CEE Incentive Award (6) | (10) | (0.02) | (10) | (0.02) |
| Increase in shares outstanding | - | (0.02) | - | (0.08) |
| Tax benefit on stock compensation (7) | - | - | 31 | 0.06 |
| Miscellaneous | (23) | (0.05) | 20 | 0.03 |
| Growth in rate base earnings (8) | 25 | 0.05 | 103 | 0.20 |
| **2017 Earnings from Operations (1)** | **$ 327** | **$ 0.63** | **$ 1,889** | **$ 3.68** |

(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 40.75 percent, except for tax benefits on stock compensation. See Footnote 3 below.

(2) Represents the impact in 2016 of the delay in the Utility's 2015 GT&S rate case. The CPUC issued its final phase two de cision on December 1, 2016, delaying recognition of the full 2016 revenue increase until the fourth quarter of 2016.

(3) Represents the timing of taxes reportable in quarterly statements in accordance with A SC 740 and results from variance s in the percen tage of quarterly earnings to annual earnings .

(4) Represents the impact of lower tax repair benefits as a result of the CPUC's final decision in the 2017 GRC proceeding.

(5) Represents timing of operational expense spending during the three months end ed December 31, 2017 as compared to the same period in 2016.

(6) Represents the Customer Energy Efficiency ("CEE") incentive award received during the fourth quarter of 2016, with no similar amount in 2017. The 2017 award of $21.9 m illion was fully offset by the reduction approved by the CPUC related to the rehearing of the 2006 – 2008 CEE incentive awards.

(7) Represents the excess tax benefit related to share-based compensation awards that vested during the twelve months ended December 31, 2017. Pursua nt to ASU 2016-09, *Compensation – Stock Compensation (Topic 718)* , which PG&E Corporation and the Utility adopted in 2016, excess tax benefits associated with vested awards are reflected in net income.

(8) Represents the impact of the increase in rate bas e authorized in various rate cases, including the 2017 GRC, during the three and twelve months ended December 31, 2017 as compared to the same periods in 2016.



**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 materiall y 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 impact of the Northern California wildfires. The Utility incurred costs of $219 million for service restoration and repairs to the Utility's facilities (includin g an estimated $97 million in capital expenditures) in connection with these fires. PG&E Corporation's and t he Utility's financial co ndition, 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 cause of one or more fires , and the d octrine of inverse condemnation applies, the Utility could be liable for property damages, interest, and attorneys' fees with out having been found negligent , which liability, in the aggregate, could be substantial. In addition to such claims, as well as c laims under other theories of liability, the Utility could be liable for fire suppression costs , evacuation costs, medical expenses, personal injury damages, and other damages if the Utility were found to have been negligent, which liability, in the aggreg ate, could be substantial and have a material effect on PG&E Corporation and the Utility . Further, the Utility also could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determine d that the Utility failed to comply with applicable laws and regulations. If the Utility were to determine that it is both probable that a loss has occurred and the amount of loss can be reasonably estimated, a liability would be recorded consistent with the principles discussed in Note 13 to Notes to the Consolidated Financial Statements in Item 8 . To the extent not offset by insurance recoveries, the liability would affect the balance sheet equity of PG&E Corporation and the Utility . (See "Enforcement and Litigation Matters" in Note 1 3 to Notes to the Consolidated Financial Statements in Item 8 and Item 1A. Risk Factors.)

- *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 significantly expand the potential shareholder 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. I n December 2017, the CPUC denied recovery of costs that San Diego Gas & Electric Company stated it incurred as a result of the doctrine o f 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. (See "Enforcement and Litigation Matters" in Note 13 to Notes to the Consolidated Financial Statements in Item 8 and Item 1A. Risk Factors.)

- *The Tax Cut and Jobs Act .* O n December 22, 2017, the U.S. government enacted expansive tax leg islation commonly referred to as the Tax Act . Among other provisions, the Tax Act reduces the federal income tax rate from 35 percent to 21 percent beginning on January 1, 2018 and eliminate s bonus depreciation for utilities. As a result of the Tax Act, beginning in 2018, PG&E Corporation and the Utility anticipate a reduction in revenues, lower effective income tax rates and lower income tax expense . In addition, the Utility expects a rate base increase primarily due to the elimination of bonus deprecia tion. (See "The Tax Cuts and Job Act of 2017" and "Regulatory Matters" in this Item 7. MD&A and Note 3 and Note 8 in the Notes to the Consolidated Financial Statements.)

- *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 rela ted fines, penalties, or other ratemaking tools that could be imposed by the CPUC, including as a result of the phase two of the proceeding, the ex parte OII and the related proposed decision, the potential recommendations that the third-party monitor ( ret ained 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-re ports. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 , Item 3. Legal Proceedings, and Item 1A. Risk Factors .)

- *The Timing and Ou tcome of Ratemaking Proceedings.* The Utility's financial results may be impacted by the timing and ou tcome of its 2019 GT&S rate case, and FERC TO18 and TO19 rate cases, as well as the recent remand decision by the Ninth Circuit regarding an ROE adder for transmission facilities. (See "Regulatory Matters – 2019 Gas Transmission and Storage Rate Case" and "Regulatory Matters − FERC Transmission Owner Rate Cases " below for more information.) The outcome of regulatory proceedings can be affected by many factors, including intervening parties' testimonies, potentia l rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.

- *The Ability of the Utility to Control and Recover Operating Costs and Capital Expenditures.* In any given year the Utility's ability to earn its author ized rate of return depends on its ability to manage costs within the amounts authorized in rate case decisions. The Utility forecasts that in 201 8 it will incur unrecovered pipeline-relat ed 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 establishe d various cost caps that will increase the risk of overspend over the rate case cycle th rough 2018. (See "Disallowance of Plant Costs" in Note 13 of the Notes to the Consolidate d Financial Statements in Item 8 .)

- *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 13 of the Notes to the Consolidated Financi al 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 finan cing arrangements and regulatory capital structure requirements resulting therefrom, adverse changes in their respective credit ratings, general economic and market conditions, and other factors. PG&E Corporation contributes equity to the Utility as neede d to maintain the Utility's CPUC-au thorized capital structure. In 201 7 , PG&E Corporation issued $416 mil lion of common stock and made equity contributions of $455 million to the Utility . PG&E Corporation forecasts that it will need to continue to issue a material amount of equity in future years, primarily to support the Utility's capital expenditures. PG&E Corporation may seek to issue additional equity to fund unrecoverable pipeline-related expenses and 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 pro vide 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 gen eration and energy storage) and state c limate 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 Cali fornia's climate change and GHG reduction objectives, which continue to be publicly supported by California policy makers notwithstanding a recent change in the fed eral approach to such matters. In order to enable the California clean energy economy, sust ained investments are required in grid modernization, renewable integration projects, energy efficiency programs, energy s torage options, EV infrastructure and s tate infrastructure modernization (e.g. rail and water projects). The Utility forecasts ove r $ 1 billion in gri d investments through 2020, which would include increased remote control and sensor technology of the grid, integration inv estments in connection with DER bi-directional energy flows and voltage fluctuations , advanced grid data analytics, g rid storage that enables renewable integration, expanded infrastructure for light, medium , and heavy-duty EVs, transmission integration for renewables, and energy efficiency and demand response programs. In addition, these changes brought about by technol ogical 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 addition, this 201 7 Form 10-K 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 2017 Form 10-K . See the section entitled "Forwa rd - 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 t o update forward-looking statements, whether in response to new information, future events, or otherwise.

**RESULTS OF OPERATIONS**

The following discussion presents PG&E Corporation's and the Utility's operating results for 2017 , 2016 , and 2015 .   See " Key Factors Affecting Financial Results " above for further discussion about factors that could affect future 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 p rovides a summary of net income av ailable for common shareholders :

| (in millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Consolidated Total | $ 1,646 | $ 1,393 | $ 874 |
| PG&E Corporation | (31) | 5 | 26 |
| Utility | $ 1,677 | $ 1,388 | $ 848 |

PG& E Corporation's net income consists primarily of income taxes, interest expense on long-term debt, and other income from investments.  The decrease in PG&E Corporation's net income for 2017, as compared to 2016 , is primarily due to the impact of the Tax Act and interest expense, partially offset by the impact of the San Bruno Derivative Litigation.  Results include approximately $30 million of realized gains and associated tax benefits related to an investment in SolarCity Corporation recognized in 2015, with no corresponding gains in 2016 or 2017.

**Utility**

The table below shows certain items from the Utility's Consolidated Statements of Income for 2017 , 2016 , and 2015 .  The table separately identifies the revenues and costs that impacted earnings from those that did not impact earnings.  In general, expenses the Utility is author ized 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 earni ngs.  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 a re primarily those that the Utility incurs to own and operate its assets.

| | 2017 | | | 2016 | | | 2015 | | |
|---|---|---|---|---|---|---|---|---|---|
| | Revenues and Costs: | | | Revenues and Costs: | | | Revenues and Costs: | | |
| **(in millions)** | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility | That Impacted Earnings | That Did Not Impact Earnings | Total Utility |
| Electric operating revenues | $ 7,897 | $ 5,230 | $ 13,127 | $ 7,955 | $ 5,910 | $ 13,865 | $ 7,442 | $ 6,215 | $ 13,657 |
| Natural gas operating revenues | 2,969 | 1,042 | 4,011 | 2,767 | 1,035 | 3,802 | 2,082 | 1,094 | 3,176 |
| **Total operating revenues** | **10,866** | **6,272** | **17,138** | **10,722** | **6,945** | **17,667** | **9,524** | **7,309** | **16,833** |
| Cost of electricity | - | 4,309 | 4,309 | - | 4,765 | 4,765 | - | 5,099 | 5,099 |
| Cost of natural gas | - | 746 | 746 | - | 615 | 615 | - | 663 | 663 |
| Operating and maintenance | 5,112 | 1,217 | 6,329 | 5,787 | 1,565 | 7,352 | 5,402 | 1,547 | 6,949 |
| Depreciation, amortization, and decommissioning | 2,854 | - | 2,854 | 2,754 | - | 2,754 | 2,611 | - | 2,611 |
| **Total operating expenses** | **7,966** | **6,272** | **14,238** | **8 ,541** | **6,945** | **15,486** | **8,013** | **7,309** | **15,322** |
| **Operating income** | **2,900** | **-** | **2,900** | **2,181** | **-** | **2,181** | **1,511** | **-** | **1,511** |
| Interest income [(1)] | | | 30 | | | 22 | | | 8 |
| Interest expense [(1)] | | | (877) | | | (819) | | | (763) |
| Other income, net [(1)] | | | 65 | | | 88 | | | 87 |
| **Income before income taxes** | | | 2,118 | | | 1,472 | | | 843 |
| Income tax provision (benefit) [(1)] | | | 427 | | | 70 | | | (19) |
| **Net income** | | | 1,691 | | | 1,402 | | | 862 |
| Preferred stock dividend requirement [(1)] | | | 14 | | | 14 | | | 14 |
| **Income Available for Common Stock** | | | **$ 1,677** | | | **$ 1,388** | | | **$ 848** |

[(1)] These items impacted earnings.

## Utility Revenues and Costs that Impacted Earnings

The following discussion presents the Utility's operating results for 2017 , 2016 , and 2015 , focusing on revenues and expenses that impacted earnings for these periods.

*Operating Revenues*

The Utility's electric and natural gas operating revenues that impacted earnings increased $ 144 m illion , or 1% in 2017 compared to 2016 , primarily due to higher electric transmission revenues .

The Utility's electric and natura l gas operating revenues that impacted earnings increased $1.2 billion or 13% in 2016 compared to 2015, primarily as a result of approximately $700 million of incremental revenues authorized in the 2015 GT&S rate case and approximately $425 million of addi tional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO 17 rate case.

*Operating and Maintenance*

The Utility's operating and maintenance expenses that impacted earnings decreased $ 675 m illion , or 12% , in 2017 compared to 2016 . In 2017, the Utility incurred $4 55 million less in disallowed charges ( t he Utility recorded a $47 million disallowance related to the Diablo Canyon settlement in 2017 as compared to $ 502 million of disallowed capital charges related to the San Bruno P enalty D ecision and 2015 GT&S rate case decision in 2016) and $ 447 million less in charges related to the Butt e fire (the Utility recorded $ 410 million in charges in 2017 as compared to $ 857 million in 2016) . These decreases were partially offset by insurance recoveries related to the Butte fire decreasing by approximately $ 275 million (the Utility recorded $350 million in insurance recoveries in 2017 as compared to approximately $ 625 million in 2016). ( S ee Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility's operating and maintenance expenses that impacted earnings increased $ 385 million , or 7% , in 2016 compared to 2015, primarily due to $857 million in charges for third-party claims, Utility clean-up, repair, and legal costs related to the Butte fire, $219 million in permanently disallowed capital spending, $34 million in charges recorded in connection with the final CPUC decision related to the natural gas distribution facilities record-keeping investigation, the federal criminal trial, and the atmospheric corrosion inspection self-report, $24 million in higher pipeline-re lated expenses and legal and regulatory related expenses during 2016, an escalation related to labor, benefits, and service contracts, and accelerated transmission and distribution project work. These increases were partially offset by $500 million in cha rges associated with the San Bruno Penalty Decision for customer refunds and fines incurred in 2015 with no corresponding charges in 2016 and approximately $125 million in lower disallowed capital charges associated with the San Bruno Penalty Decision in 2 016. Additionally, the Utility recorded approximately $576 million more in insurance recoveries (in 2016, the Utility recorded $625 million in insurance recoveries related to the Butte fire as compared to $49 million of insurance recoveries for third-part y claims related to the San Bruno accident in 2015 ) .

T he 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 an y additio nal charges associated with costs related to the Butte fire. (See Item 1A. Risk Factors above and Note 1 3 of the Notes to the Consolidated Financial Statements in Item 8. )

*Depreciation, Amortization, and Decommissioning*

The Utility's depreciation, amortization, and decommissioning expenses increased $ 100 million , or 4% in 2017 compared to 2016 and $ 143 million , or 5% in 2016 compared to 2015 . In 201 7 , the increase was primarily due to the impact of capital additions and higher depreciation rates as authorized by the CPUC in the 2017 GRC . In 201 6 , the increase was primarily due to the impact of capital additions.

*Intere st Expense*

The Utility's interest expenses increased by $ 58 million, or 7% in 2017 compared to 2016, primarily due to the issuance of additional long-term debt. The Utility's interest expenses increased by $ 56 million , or 7% in 201 6 compared to 201 5 , primarily due to the issuance of additional long-term debt.

*Interest Income and Other Income, Net*

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

*Income Tax Provision*

The Utility's income tax provision increased $ 357 million in 2017 compared to 2016 . The increase in the tax provision was primarily the result of the statutory tax effect of higher pre-tax income in 201 7 compared to 201 6 and an adjustment required to record the change in deferred tax balances due to tax reform in 2017 with no comparable adjustment in 2016. (For more information see "Tax Reform" below and Note 8 of the Consolidated Financial Statements.)

The Utility's income tax provision increased $89 million in 2016 compared to 2015. The increase in the tax provis ion was primarily the result of the statutory tax effect of higher pre-tax income in 2016 compared to 2015, partially offset by higher tax benefits from property-related timing differences in 2016 compared to 2015. The higher effective tax rate was driven by higher pre-tax earnings in 2016, partially offset by rate impact from property-related timing differences.

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

| | 2017 | 2016 | 2015 |
|---|---|---|---|
| Federal statutory income tax rate | 35.0% | 35.0% | 35.0% |
| Increase (decrease) in income tax rate resulting from: | | | |
| State income tax (net of federal benefit) (1) | 1.6 | (2.2) | (4.8) |
| Effect of regulatory treatment of fixed asset differences (2) | (16.8) | (23.4) | (33.7) |
| Tax credits | (1.1) | (0.8) | (1.3) |
| Benefit of loss carryback | - | (1.1) | (1.5) |
| Non-deductible penalties (3) | 0.4 | 0.8 | 4.3 |
| Tax Reform Adjustment (4) | 3.0 | - | - |
| Other, net (5) | (2.0) | (3.5) | (0.2) |
| **Effective tax rate** | **20.1%** | **4.8%** | **(2.2)%** |

(1) Includes the effect of state flow -through ratemaking treatment. In 2016 and 2015, amounts reflect an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions. The 2017 amount reflects an agreement with the IRS on a 2013 audit related to generation repairs deductions.

(2) I nclude s the effect of federal flow-through ratemaking treatment for certain property-related costs a s authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacted 2016 and 2017. All amounts are impacted by the level of income before income taxes. The 2014 GRC and 2015 GT&S rate case decisions authorized reve nue 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 Utilit y 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 a nd 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.

(3) Primarily represen ts the effect s of a non-tax deductible penalty asso ciated with the Butte fire for 2017, non-tax deductible fines and penalties associated with the natural gas distribution facilities record-keeping decision for 2016 and the effects of the San Bruno Penalty Decision for 2015 .

(4) Represents the required ad justment to deferred tax balances, due to the federal income tax rate being lowered from 35% to 21% beginning in 2018 as a result of the enactment of the Tax Act.

(5) These amounts primarily represent the impact of tax audit settlements.

**Utility Revenues and Costs that did not Impact Earnings**

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

*Cost of Electricity*

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 prog ram, and realized gains and losses on price risk management activities. (See Note 9 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's total purchased power is driven by customer demand, the availability of the Utility's own g eneration facilities (including Diablo Canyon and its hydroelectric plants), and the cost-effectiveness of each source of electricity .

| (in millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Cost of purchased power | $ 4,039 | $ 4,510 | $ 4,805 |
| Fuel used in own generation facilities | 270 | 255 | 294 |
| **Total cost of electricity** | **$ 4,309** | **$ 4,765** | **$ 5,099** |
| Average cost of purchased power per kWh (1) | $ 0.140 | $ 0.109 | $ 0.100 |
| **Total purchased power (in millions of kWh) (2)** | **28,750** | **41,324** | **48,175** |

(1) Average cost of purchased power was impacted primarily by lower Utility electric customer demand due to their departure to CCAs or direct access providers and a larger percentage of higher cost renewable energy resource s being allocated to fewer remaining Utility electric customers. See further discussion in Item 7. MD&A, "Legislative and Regulatory Initiatives - Power Charge Indifference Adjustment OIR ", below.

(2) The decrease in purchased power for 2017 compared to 2016 was primarily due t o lower Utility electric customer demand and an increase in generation from hydroelectric facilities.

*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 9 of the Notes to the Consolidated Financial Statements in Item 8.) The Utility's cost of natural gas is impacted by the market price of natural gas, changes in the cost of storage and transportation, and changes in customer demand.

| **(in millions)** | **2017** | **2016** | **2015** |
|---|---|---|---|
| Cost of natural gas sold | $ 627 | $ 481 | $ 518 |
| Transportation cost of natural gas sold | 119 | 134 | 145 |
| **Total cost of natural gas** | **$ 746** | **$ 615** | **$ 663** |
| Ave rage cost per Mcf [1] of natural gas sold | $ 2.97 | $ 2.45 | $ 2.74 |
| **Total natural gas sold (in millions of Mcf) [2]** | **211** | **196** | **189** |

[1] One thousand cubic feet
[2] The increase in natural gas sold for 2017 compared to 2016 was primarily due to cooler temperatures and resulted in additional customer heating demand.

*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. For 201 7 , 201 6, and 201 5 , no material amounts were incurred above authorized amounts.

## LIQUIDITY AND FINANCIAL RESOURCES

### Overview

On December 20, 2017, the Boards of Directors of PG&E Corporation and the Utili ty 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 uncertaint y related to the causes of and potential liabilities associated with the Northern California wildfires. ( See Item 1A. Risk Factors and Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

The Utility's ability to fund operations , fi nance 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 a nd 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 issuan ces to maintain its CPUC-authorized capital structure consisting of 52% equity and 48% debt and preferred sto ck. (See "R egulatory Matters" in Item 7. MD&A. ) The Utility relies on short-term debt, including commercial paper, to fund temporary financing ne eds.

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 deb t, 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 pot ential 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 cost s. 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. In December 2017, following PG&E Corporation's announcement that it was su spending its dividend due to the uncertainty related to the causes and potential liabilities associated with the Northern California wildfires, all of the ratings of PG&E Corporation and the Utility were placed under review for downgrade by Moody's Investo r Services. Additionally, in December 2017, Standard & Poor's Global Ratings lowered the Utility's preferred stock credit rating and placed all of the ratings of PG&E Corporation and the Utility on CreditWatch with negative implications. 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 positions . (See Note s 9 and 13 of the Notes to the Consolidated Financial Statements in Item 8.)

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. T he Utilit y's equity needs will also 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 describe d in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Fina ncial Statements in Item 8 . 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 matt ers. (See Item 1A. Risk Factors.)

As a result of the Tax Act, the Utility anticipates an annual reduction to revenue requirements of approximat ely $500 million starting in 2018. In addition to this reduction in future revenue requirements, the Tax Act's other provisions, in particular the elimination of bonus depreciation, are expected to accelerate when PG&E Corporation resumes paying federal taxes; although future taxes will be lower due to the lower federal tax rate. PG&E Corporation now expects to pay federal taxes starting in 2020 , although that timing would be impacted by any significant changes to future results of operations . Additionally, because the revenue redu ction is expected to precede the reduction in federal income tax payments, PG&E Corporation's and the Utility's operating cash flows will be negatively impacted resulting in additional financing need s .

**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 Financings***

In February 2017, the Utility's $250 million floating rate unsecured term loan, issued in March 2016, matured and was repaid. Additionally, in February 2017, the Utility entered into a $250 million floating rate uns ecured term loan maturing on February 22, 2018.

In March 2017, the Utility issued $400 million principal amount of 3.30% senior notes due March 15, 2027 and $200 million principal amount of 4.00% senior notes due December 1, 2046. The proceeds were used for general corporate purposes, including the repayment of a portion of the Utility's outstanding commercial paper.

In November 2017, the Utility issued $1,150 million principal amount of 3.30% senior notes due December 1, 2027 and $850 million principal amount of 3.95% senior notes due December 1, 2047. The proceeds were used to repay all of the $700 million outstanding principal amount of its 5.63% senior notes due November 30, 2017, all of the $250 million floating rate unsecured term loan maturing Feb ruary 22, 2018 and $400 million of the 8.25% senior notes due October 15, 2018, and the balance, for general corporate purposes.

In November 2017, the Utility issued $500 million of floating rate senior notes due November 28, 2018. The proceeds were use d towards repayment of the $250 million unsecured floating rate notes due November 30, 2017 and the balance was used to support the Northern California wildfire response efforts.

On January 9, 2018, the Utility sent a notice of redemption to redeem all $4 00 million aggregate principal amount of the 8.25% senior notes due October 15, 2018 on February 18, 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.

***Equity Financings***

In February 2017, PG&E Corporation amended its February 2015 EDA providing for the sale of PG&E Corporation common stock having an aggregate gross price of up to $275 million. During the tw elve months ended December 31, 2017, PG&E Corporation sold 0.4 million shares of its common stock under the February 2017 EDA for cash proceeds of $ 28.4 million, net of commissions paid of $ 0.2 million. There were no issuances under the February 2017 EDA for the three months ended December 31, 2017. As of December 31, 2017, the remaining gross sales available under this agreement were $ 246.3 million.

PG&E Corporation also issued common stock under the PG&E Corporation 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans. During 2017, 7.4 million shares were is sued for cash proceeds of $ 366.4 million under these plans.

The proceeds from these sales were used for general corporate purposes, including the contribution of equity to the Utility . For the year ended December 31, 2017 , PG& E Corporation made equity contributions to the Utility of $ 455 million.

***Pollution Control Bonds***

In June 2017, the Utility repurchased and retired $345 million principal amount of pollution control bonds Series 2004 A through D. Additionally, in June 2017, the Utility remarketed three series of pollution control bonds, previously held in treasury, totaling $145 million in principal amount. Series 2008 F and 2010 E bear interest at 1.75% per annum. Although the stated maturity da te for Series 2008 F and 2010 E is November 1, 2026, these bonds have a mandatory redemption date of May 30, 2022 . Series 2008 G bears interest at 1.05% per annum and matures on December 1, 2018.

***Revolving Credit Facilities and Commercial Paper Programs***

In May 2017, PG&E Corporation and the Utility each extended the termination dates of their existing revolving credit facilities by one year from April 27, 2021 to April 27, 2022. At December 31, 2017, PG&E Corporation and the Utility had $ 168 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 Consolidated Financial Statements in Item 8.)

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 year ended December 31, 201 7 , PG&E Corporation and the Utility had an average o utstanding commercial paper balance of $ 81 million and $ 469 million, and a maximum outstanding balance of $ 161 million and $ 1.1 billion, respectively. At December 31, 201 7 , PG&E Corporation and t he Utility had outstanding co mmercial paper balances of $ 132 million and $ 50 m illion , respectively. (See Note 4 of the Notes to the Consoli dated Financial Statements in Item 8.)

T he 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. A t December 31, 2017, PG&E Corporation's and the Utility's total consolidated debt to total consolidate d capitalization was 50% and 49% , respectively . PG&E Corporation's revolving credit facil ity agreement also requires that PG&E Corporation own s , 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 C orporation's and the Utility's assets and other fundamental changes. A t December 31, 2017 , PG&E Corporation and the Utility were in compl iance with all covenants under their respective revolving credit facilities.

**Dividends**

The Board of Directors of P G&E Corporation and the Utility each has the authority to declare dividends on PG&E Corporation's common stock and the Utility's common and preferred stock, respectively. Dividends are not payable unless and until declared by the applicable Board of Direc tors. Each Board of Directors retains authority to change the respective common or preferred stock dividend policy and dividend payout ratio or rate at any time, especially if unexpected events occur that would change their view as to the prudent level of cash conservation.

***PG&E Corporation***

For the first quarter of 201 7 , the Board of Directors of PG&E Corporation declared a common stock dividend of $ 0.49 per share. In May 2017 , the Board of Directors of PG&E Corporation approved a new annual common stock dividen d of $ 2.12 per share. As a result, for the second and third quarter s of 201 7 , the Board of Directors of PG&E Corporation declared a common stock dividend of $0. 53 per share . In 2017, total dividends declared were $ 1.55 per share. For the first q uarter of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.455 per share. For each of the second, third and fourth quarters of 2016, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.4 9 per share . In 2016, total dividends declared were $1.925 per share. For each of the quarters in 2015, t he Board of Directors of PG&E Corporation declared a common stock dividend of $0.4 55 per share , for annual dividends of $1.82 per share. Dividends paid to common shareholders by PG&E Corporation were $ 1.0 b illion in 2017, $ 921 million in 2016, and $ 856 million in 2015 .

***Utility***

For the first quarter of 2017, the Board of Directors of the Utility declared a common stock dividend of $244 million to PG&E Corporation. For the second and third quarter of 2017, the Board of Directors of the Utility declared common stock dividends of $270 million to PG&E Corporation. In 2017, total dividends paid by the Utility to PG&E Corporation were $ 784 million. For the first quarter of 2016, the Board of Directors of the Utility declared a common stock dividend of $ 179 million to PG&E Corporation. For each of the second, third and fourth quarters of 2016, the Board of Directors of the Utility d eclar ed common stock dividends of $ 244 million to PG&E Corporation . In 2016, total dividends paid by the Utility to PG&E Corporation were $ 911 million. For each of the quarters in 2015 , the Board of Directors of the Utility declared common stock dividends of $ 179 million to PG&E Corporation for annual dividends paid of $ 716 million. In addition, the Utility p aid $ 14 million of dividends on preferred stock in each of 2017, 201 6, and 2015 . The Ut ility's preferred stock is cumulative and any dividends in arrears must be paid before the Utility m ay pay any common stock dividends.

**Utility Cash Flows**

The Utility's cash flows were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in millions)** | **2017** | **2016** | **2015** |
| Net cash provided by operating activities | $ 5,916 | $ 4,344 | $ 3,747 |
| Net cash used in investing activities | (5,650) | (5,526) | (5,211) |
| Net cash provided by financing activities | 110 | 1,194 | 1,468 |
| **Net change in cash and cash equivalents** | **$ 376** | **$ 12** | **$ 4** |

***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 2017, net cash provided by operating activities increased by $ 1.6 billion compared to 2016. This increase was primarily due to additional electric and natural gas operating revenues collected as authorized by the CPUC in the 2015 GT&S rate cas e, the $400 million refund to natural gas customers in the second quarter of 2016, as required by the San Bruno Penalty Decision (with no corresponding activity in 2017), and the receipt of approximately $300 million of insurance recoveries related to the Butte fire in 2017 as compared to $50 million of insurance recoveries related to the Butte fire during 2016.

During 2016 , net cash provided by operating activities in creased by $ 597 million compared to 2015 . This in crease was partially due to the Utili ty receiving an additional $170 million in tax refunds in 2016 as compared to 2015. The remaining increase was primarily due to fluctuations in activities within the normal course of business such as timing and amount of customer billings and vendor billi ngs 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 am ounts 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 the phase two of the proceeding, the ex parte OII and the related proposed decision, costs associated with potential recommendations that the third-p arty 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 payment s and reduce revenue requirements, resulting in lower operating cash flows;
- the timing and outcome s of the 2019 GT&S, TO18, and TO19 rate cases and other ratemaking and regulatory proceedings ;
- the timing and amount of costs the Utility incurs, but does n ot recover, associated with its electric and natural gas system s ; 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 $124 million during 2017 as compared to 2016 primarily due to an increase in capital expenditures. Net cash used in investing activities in creased by $ 315 million during 2016 as compared to 2015 primarily due to an increase of approximately $440 million in capital expenditures, partially offset by an increase in restricted cash released from escrow by approximately $160 million.

Future cash flows used in investing activities are largely de pendent 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***

During 2017, net cash provided by financing activities decreased by $ 1.1 billion as compared to 2016. This decrease was primarily due to net commercial repayments of $972 million in 2017 as compared to net rep ayments of $9 million in 2016. During 2016 , net cash pro vided by financing activities de creased by $ 274 million as compared to 2015 . Cas h 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 issu ances 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.

## CONTRACTUAL COMMITMENTS

The following table provides information about PG&E Corporation's and the Utility's contractual commitments at December 31, 2017 :

| | Payment due by period | | | | |
|---|---|---|---|---|---|
| (in millions) | Less Than 1 Year | 1-3 Years | 3-5 Years | More Than 5 Years | Total |
| **Utility** | | | | | |
| Long-term debt [1]: | $ 1,253 | $ 3,117 | $ 2,523 | $ 25,114 | $ 32,007 |
| Purchase obligations [2]: | | | | | |
| Power purchase agreements: | 3,148 | 6,169 | 5,539 | 27,188 | 42,044 |
| Natural gas supply, transportation, and storage | 388 | 315 | 186 | 357 | 1,246 |
| Nuclear fuel agreements | 96 | 245 | 130 | 151 | 622 |
| Pension and other benefits [3] | 351 | 701 | 701 | 351 | 2,104 |
| Operating leases [2] | 44 | 81 | 63 | 138 | 326 |
| Preferred dividends [4] | 14 | 28 | 28 | - | 70 |
| **PG&E Corporation** | | | | | |
| Long-term debt [1]: | 8 | 354 | - | - | 362 |
| **Total Contractual Commitments** | **$ 5,302** | **$ 11,010** | **$ 9,170** | **$ 53,299** | **$ 78,781** |

(1) Includes interest payments over the terms of the debt. Interest is calculated using the applicable interest rate at December 31, 2017 and outstanding principal for each instrument with the terms ending at each instrument's maturity. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)
(2) See "Purchase Commitments" and "Other Commitments" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.
(3) See Note 11 of the Notes to the Consolidated Financial Statements in Item 8. Payments into the pension and other benefits plans are based on annual contribution requirements. As these annual requirements continue indefinitely into the future, the amount shown in the column entitled "more than 5 years" represents only 1 year of contributions for the Utility's pension and other benefit plans.
(4) Beginning with the three-month period ending January 31, 2018, quarterly cash dividends on the Utility's preferred stock were suspended. While the timing of cumulative dividend payments is uncertain, it is assumed for the table above to be payable within a fixed period of five years based on historical performance. (See Note 6 of the Consolidated Financial Statements in Item 8.)

The contractual commitments table above excludes potential payments associated with unrecognized tax positions. Due to the uncertainty surrounding tax audits, PG&E Corporation and the Utility cannot make reliable estimates of the amounts and periods of future payments to major tax jurisdictions related to unrecognized tax benefits. Matters relating to tax years that remain subject to examination are discussed in Note 8 of the Notes to the Consolidated Financial Statements in Item 8.

### 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 (the Utility's commodity purchase agreements) in Item 8.

## 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 13 of the Notes to the Consolidated Financial Statements in Item 8 and Legal Proceedings in Item 3. 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.

## R EGULATORY 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.

The Utility is still analyzing the impact of the Tax Act on revenue requirements and rate base for the 2017 GRC, the 2015 GT&S Rate Case, the recently submitted 2019 GT&S Rate C ase, and the pending TO19 rate case. However, on an aggregate basis, the Utility currently anticipates an annual reduction to revenue requirements of approximately $500 million starting in 2018, and incremental increases to rate base of approximately $500 million in 2018 and $800 million in 2019, as a result of the Tax Act.

As a result of the Tax Act, the Utility intends to file by the end of March 2018 (i) revised revenue requirements and rate base in its 2017 GRC (for years 2018 and 2019) and 2015 G T&S rate case (for 2018) as well as a proposed implementation plan in connection thereto, and (ii) revised revenue requirement and rate base forecast in its 2019 GT&S rate case. The Utility is unable to predict the timing and outcome of the CPUC decision in connection with such filings. As discussed below, the 2017 GRC final decision established a tax memorandum account to track revenue differences resulting from tax law changes, among other items, for disposition in the 2020 GRC. The March filing s will accelerate that timing. (Se e "Tax Cut s and Jobs Act of 2017" in Item 7. MD&A and Note 3 and Note 8 in the Notes to the Consolidated Financial Statements.)

***2017 General Rate Case***

On May 11, 2017, the CPUC issued a final decision in the Utility's 2017 GR C, 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 ele ctric 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 partie s jointly submitted to the CPUC on August 3, 2016 (the "settlement agreement"). Modifications from the settlement agreement to the final decision included a tax memorandum account and approval of a stand-alone application with the CPUC or a filing in the CPUC's ongoing residential rate reform proceeding to recover customer outreach and other costs incurred as a result of residential rate reform implementation. The new tax memorandum account will track any revenue differences resulting from changes in inco me tax expense caused by net revenue changes, mandatory or elective tax law changes, tax accounting changes, tax procedural changes, or tax policy changes during the 2017 through 2019 GRC period. The account will remain open and the balance in the account will be reviewed in every subsequent GRC proceeding until a CPUC decision closes the account.

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. The following table shows the revenue requirement amounts approved in the final decision based on line of business and cost category as well as the differences between the 2016 authorized rev enue requirements and the amounts approved in the final decision:

| (in millions)<br>**Line of Business:** | **Amounts Approved in Final Decision** (1) | **Increase/ (Decrease) 2016 vs. Final Decision** |
|---|---|---|
| Electric distribution | $ 4,151 | $ (62) |
| Gas distribution | 1,738 | (3) |
| Electric generation | 2,115 | 153 |
| **Total revenue requirements** | **$ 8,004** | **$ 88** |

| (in millions)<br>**Cost Category:** | | |
|---|---|---|
| Operations and maintenance | $ 1,794 | $ 131 |
| Customer services | 334 | 15 |
| Administrative and general | 912 | (99) |
| Less: Revenue credits | (152) | (21) |
| Franchise fees, taxes other than income, and other adjustments | 170 | 132 |
| Depreciation (including costs of asset removal), return, and income taxes | 4,946 | (70) |
| **Total revenue requirements** | **$ 8,004** | **$ 88** |

(1) Amounts approved in the final decision are the same as the amounts that were proposed in the settlement agreement.

As required by the final decision, the Utility has submitted a variety of compliance filings, including filings on June 12, 2017, which provides accounting for the January 2017 $300 million expense reduction announcement and on July 10, 2017, providing an update of the cost effectiv eness study for the SmartMeter™ Upgrade project. On February 8, 2018, the CPUC exte nded the statutory deadline for the 2017 GRC from February 8, 2018 to August 9, 2018, in order to allow for comments and CPUC action on any PD on the SmartMeter ™ Upgrade cost effectiveness study, as well as one other remaining GRC compliance item.

***2020 General Rate Case***

The Utility expects to file the 2020 GRC by September 1, 2018. On November 30, 2017, the Utility filed its first RAMP submittal to the CPUC in advance of its 2020 GRC filing. The RAMP is a new CPUC requirement directing each large 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 applica tion. The objective of this filing 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.

The SED is expected to submit a report on the Utility's RAMP submitta l and hold a workshop on the report, after which parties will have the opportunity to file comments. The RAMP results will be incorporated in the Utility's 2020 GRC.

***2015 Gas Transmission and Storage Rate Case***

During 2016, the CPUC issued final decisio n s in phase one and phase two of the Utility's 2015 GT&S rate case . T he 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 stor age 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 cau sed 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 d isallow ed $120 m illion of that amount and ordered that the remaining $57 6 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding . A draft of the audit report is expected in the first quarter of 2018. The decision established new one-way balancing accounts to track costs as well as various cost caps that will increase the risk of disallowance over the current rate case cycle . The Utility would be required to take a charge i n the future if the CPUC's audit of 2011 through 2014 capital spending resulted in additional permanent disallowance.

In August 2016 and January 2017, TURN, ORA and Indicated Shippers filed applications for rehearing of the phase one and phase two decisi ons, respectively. The Utility cannot predict when or if the CPUC will grant the rehearing s or if it will adop t 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 pr ogram. As directed by the CPUC, on August 23, 2017, the Utility provided supplemental information to the CPUC regarding the PFM. The Utility is unable to predict if and when the CPUC would adopt the PFM . In the event the PFM is not adopted and the Utili ty fails to perform the mandated new cathodic protection systems, the Utility could incur fines and penalties, the amount of which the Utility is unable to predict.

***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 additio nal 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 ultimatel y 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 IRS's October 5, 2017 private letter ru ling 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) the DOGG R, which issued six new safety and reliability natural gas storage measures in 2016 in response to the 2015 Southern California natural gas storage leak in Aliso Canyon; (2) the PHMSA, which issued interim final rules, effective January 18, 2017, that addr ess 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 expendit ures in the areas of gas leak repair, leak survey, and high consequence area identification, among other things.

In addition, DOGGR is planning to complete its final rulemaking on new gas storage safety rules. The draft rules, that were released for comments on May 19, 2017, include a requirement for natural gas storage operators to perform well integrity assessments every two years and to eliminate possibl e single points of failure from natural gas storage wells. The implementation timeframe and requirements under the PHMSA's proposed regulations currently are being challenged in federal courts. In its application, the Utility proposes a new two-way Gas S torage 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.

In addition to costs related to new natural gas storage safety and environmental regulations, the Utility proposed increased infrastructure investments over the 2019 to 2021 period to continue its efforts to improve overall system safety by: (1) making approximately 1,100 miles of transmission pipelines capable of in-line inspection; (2) performing in-line inspections of over 2,100 miles of transmission pipeline, or approximately one-third of total miles; (3) testing or replacing all pipeline without a test record (or with a test record that does not meet the Utility's documentation requirements) by 2027; (4) replacing vintage pipeline for other safety or reliability issues; and (5) automating valves in areas where there is a significant potential impact.

A prehearing conference took place on January 4, 2018, and established a procedural schedule. Testimony will be served near the end of second quarter of 2018 and evidentiary hearings, if needed, will begin in the third quarter of 2018. As stated above, the Utility expects to file an update of its revenue requirement forecast to reflect the Tax Act by the end of March 2018.

**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 is $6.7 billion. The Utility is also 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 will 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 chief judge issued an order terminating the settlement procedures due to an impasse in the settlement negotiations reported by the parties.

On August 22, 2017, the FERC trial staff submitted testimony. The table below summarizes the differences between the amount of revenue requirement increases included in the Utility's request and the testimony submitted by the FERC trial staff:

| (in millions) | Amounts requested by the Utility | Amounts proposed by the FERC trial staff |
|---|---|---|
| Revenue Requirement | $ 1,718 | $ 1,353 |
| Return on Equity | 10.90% | 8.46% |
| Composite Depreciation Rate | 3.26% | 2.08% |

Additionally, intervenors provided testimony on July 5, 2017 and the Utility submitted rebuttal testimony on October 9, 2017. Hearings in this proceeding took place January 9 through January 30, 2018, and an initial decision is expected on or before June 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.

*Trans mission Ow ner Rate Case for 2018 (the "TO19 rate case")*

On July 2 7 , 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 2 017 revenue req uirement of $1.72 billion. The forecasted network transmission rate base for 2018 is $6.9 billion. The Utility is also seeking a n ROE of 10.75%, which includes an incentive component of 50 basis points for the Utility's continuing participation in the CAIS O. 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 eff ective date for rate changes. The next settlement conference is scheduled for May 16, 2018. FERC also ordered that the hearings will be held in abeyance pending settlement discussion among the parties.

On September 29, 2017 , several of the parties that have intervened in the TO1 9 rate case filed a complaint at the FERC, and requested that the complaint be consolidated with the TO19 rate case. The 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 TO1 9 is that the Utility's revenue requirement should be set at a lower level than the settled revenue requirement approved by FERC in TO17, FERC order refunds to that lower level deter mined in the TO1 8 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.

*Trans mission Owner Rate Cases for 2015 and 2016 (the "TO16" and "TO17" rate cases)*

On January 8, 2018, the Ninth Circuit Court of Appeals issued an opinion reversing FERC's decisions in the TO16 and TO17 rate cases to grant the Utility a 50 basis point ROE incentive adder for continued participation in the CAISO. The decision has been remanded to FERC for further proceedings consistent with the Court of Appeals' opinion. If FERC makes findings consistent with the Ninth Circuit Court of Appeals' opinion, 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 d ecisions lacked, then the Utility would not owe any refunds for this issue for TO16 or TO17. The Utility is unable to predict the outcome and timing of FERC's response to this opinion.

**Diablo Canyon Nuclear Power Plant**

*Joint Proposal for Plant Retiremen t*

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 applicati on 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 em ployee retention program;
- authorized rate recovery for an employee re training 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 s chedule.

During the year ended December 31, 2017, the Utility incurred pre-tax charges of $ 47 million related to the retireme nt of Diablo Canyon including $24 million for cancelled projects and $ 23 million for disallowed license renewal costs. The Utilit y does not expect to incur additional charges as a result of the CPUC's final decision , other than additional project cancellation costs that the Utility does not expect to be material .

The Joint Parties determined that they will not seek a rehearing on the CPUC final decision. In accepting the CPUC's decision to retire Diablo Canyon, the Utility will withdraw its license renewal application at the NRC .

*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 s tructures 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 Utilit y 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 yea rs. 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 fr om 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 th e 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 Aca demy 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.

*Asset Retirement Obligations*

The Utility expects that the decommissioning of Diablo Canyo n 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 c osts from customers through a non-bypassable charge that the Utility expects will continue until those costs are fully recovered.

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

The Utility expects to file its 2018 NDCTP application in late 2018 or early 2019. (See "Asset Retirement Obligations" in Note 2 to the Consolidated Financial Statements in Item 8.)

**CPUC Cost of Capital**

On July 13, 2017, the CPUC issued a final decision adopting, with no modifications to it , the PFM filed in February 2017 by San Diego Gas & Electric Company, Southern California Gas Company, Southern California Edison, the ORA, TURN, and the Utility.

The final decision extends the Utility's next cost of capital application filing deadline by two years to April 22, 2019, for the year 2020. The final decision also reduces the Utility's authorized ROE from 10.40% to 10.25%, effective January 1, 2018, and resets the Utility's authorized cost of long-term debt and preferred stock effective January 1, 2018. In addition, the decision suspends the cost of capital adjustment mechanism to adjust cost of capital for 2018, but allows the adjustment mechanism to o perate for 2019 if triggered. If the mechanism is activated for 2019, the Utility's cost of capital, including its new ROE of 10.25%, will be adjusted according to the ex isting terms of the mechanism. The Utility's current capital structure of 52% common equity, 47% long-term debt, and 1% preferred equity remains unchanged.

The final decision also leaves the proceeding open to facilitate gathering of information to inform the next cost of capital proceeding, as well as to provide a possible venue in whi ch to consider whether the Utility's ROE should be reduced until any recommendations that the CPUC may adopt in the second phase of its safety culture investigation are implemented, as described in the May 8, 2017 scoping m emo a nd r uling issued in the Safe ty Culture OII.

On September 29, 2017, the Utility submitted an advice letter to the CPUC, updating its cost of capital and the estimated revenue requirement impacts with an effective date of January 1, 2018. The long-term debt cost , reset to 4.89%, ref lects actual embedded costs as of the end of August 2017 and forecasted interest rates for the new long-term debt expected to be issued for the remainder of 2017 and all of 2018. Changes in market interest rates may have material effects on the cost of th e Utility's future financings, but will not affect the authorized cost of capital in 2018.

The Utility expects to file its next cost of capital application in 2019.

**Application to Establish a Wildfire Expense Memorandum Account**

On July 26, 2017, the U tility 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 appli cation, 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 wildfire s , 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) 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 credi ted 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 W EMA. A prehearing conference was held on December 8, 2017, and a scoping memo was issued on January 11, 2018. The Utility filed opening briefs with the CPUC on January 25, 2018 and other parties' briefs are expected to be filed in February 2018. The Uti lity cannot predict the 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 authorize s 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 preventi on and vegetation management work in response to the se vere 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 a pproval.

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 drought mitigation and emergency response activities for declared disasters that occurred from D ecember 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 tariff revenue requirement request be reduced by $29 million, from $146 million to $117 million. The Utility has requested that these costs be recovered through rates in 2018 and 2019 . PG&E Corp oration and the Ut ility are unable to predict the outcome of this proceeding.

The Utility expects to submit its 2018 CEMA application to the CPUC in the second quarter of 2018 .

**Other Regulatory Proceedings and Initiatives**

*Electric Distribution Resources Plan*

As required by California law, on July 1, 2015, the Utility filed its proposed DRP for approval by the CPUC. The Utility's plan identifies optimal locations on its electric distribution system for deployment of DERs. The Utility's proposa l 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.

On February 27, 2017, the CPUC issued a ruling that seeks the development of a p rocess for incorporating DER forecasts into the DRP that takes into consideration the coordination with other statewide planning and forecasting processes such as the CEC's Integrated Energy Policy Report. This ruling mandated the Utility, along with the other California IOUs, to develop a draft joint proposal for the CPUC and stakeholder consideration on the process for developing DER forecasts. On June 9, 2017, the IOUs submitted a draft joint proposal for CPUC and stakeholder consideration. The CPUC is sued a PD on December 8, 2017, requiring the IOUs to use the CEC's DER forecast for the 2018-2019 distribution planning cycle. The Utility has historically used the CEC forecast for planning and will have the opportunity to adjust forecasts for EV, photov oltaic , and energy storage during the intermediate years. The PD also requires the IOUs to develop an alternate planning forecast scenario in 2018 to establish a method for calculating costs and benefits for DER grid integration to better inform DER sourci ng policies. Workshops to discuss the joint proposal will continue in early 2018 and a final decision is expected from the CPUC by the end of the first quarter of 2018.

On June 30, 2017, the CPUC issued another ruling soliciting stakeholder responses on questions set forth in a CPUC staff white paper on proposing a DIDF. The DIDF aims to establish a process for identifying distribution deferral opportunities for DERs. Stakeholder comments on DIDF were submitted on August 7, 2017, with reply comments sub mitted on August 18, 2017. On December 8, 2017, the CPUC issued a PD requiring an annual grid needs assessment and an annual distribution deferral opportunity report, as part of the annual DRP for greater transparency on infrastructure investments. The g rid needs assessment report will identify critical overload areas on the grid. The distribution deferral opportunity report will document the Utility's proposed distribution needs and identify DER deferral opportunities to be reviewed by the Distribution Planning Advisory Group for prioritizing DER deferral projects. The PD proposes to adopt 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 an nual payments for DER deferral contracts. The Utility expects a final decision from the CPUC in the first quarter of 2018.

*Integrated Distributed Energy Resources Proceeding – Regulatory Incentives Pilot Program*

On April 4, 2016, the CPUC issued a ruling proposing to establish, on a pilot basis, an interim program offering regulatory incentives to the Utility and the other two large California IOUs for the deployment of cost-effective DERs. The ruling 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 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 motiv ating utilities to source DERs. On October 27, 2017, the CPUC issued a draft resolution that proposed modifications to the Utility's pilot program. On December 14, 2017, the CPUC granted the Utility's November 20, 2017 request to cancel the current pilot project proposa l due to the damage of the Utility's facilities in the area of the Northern California wildfires and propose a new pilot program location by May 1, 2018.

*2015 – 2016 Energy Efficiency Incentive Awards*

On December 1 4 , 2017, the CPUC approved a fina l 2015 – 2016 energy savings performance incentive award of $21.9 million, compared to the Utility's request of $24.7 million. The award was fully offset by a portion of the remaining reduction approved in the settlement agreement related to the rehearing o f the 2006 – 2008 risk/reward incentive mechanism. The settlement agreement requires the Utility to reduce future energy efficiency shareholder incentives by a total of $29.1 million, of which $5.8 million was used to offset the 2014 – 2015 award. The re maining settlement reduction of $1.3 million will be offset against future energy saving performance incentive awards.

**LEGISLATIVE AND REGULATORY INITIATIVES**

The California Legislature and the CPUC have adopted requirements, policies , and decisions to implement new state law requirements applicable to natural gas storage facilities , accommodate the growth in distributed electric generation resources (including solar installations), increase the amount of renewable energy delivered to customers, improve fire safety regulations, and foster the development of a state-wide electric vehicle charging infrastructure to encourage the use of electric vehicles. In addition, the CPUC continues to implement state law requirements to reform electric rates to more cl osely reflect the utilities' actual costs of service, and reduce cross-subsidizat ion among customer rate classes . CPUC proceedings related to some of these matters are discussed below.

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

*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 on how to allocate costs associated with long-term power commitments in a manner that ensures all customers are treated equally. At issue is how customers within communities that choose to i mplement CCA power arrangements and those served under direct access pay for their share of the costs. The utilities believe that these customers are not paying their full share of costs associated with the long-term commitments, which results in other cu stomers paying more, which is inconsistent with state law. The Utility is committed to helping create a cost allocation method that treats all customers fairly and equally, whether they continue to receive service from the Utility or choose a CCA or direc t access provider. The Utili ty 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 wil l 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 syste m 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, and should not be considered a follow-up to the CPUC and Energy Commission Joint En Banc on Customer Choice in California. 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 departing load customers. Testimony is scheduled for the first quarter of 2018. Evidentiary hearings , if needed, are sche duled for the second quarter of 2018 and a proposed decision is expected by the third quarter of 2018.

*Customer Choice*

On May 19, 2017, California energy companies, along with other stakeholders discussed customer choice and the future of California's el ectric industry at a CPUC "en banc" meeting. Specifically, the goal of the meeting was to frame a discussion on the trends that are driving change within California's electricity sector and overall clean-energy economy and to lay out elements of a path fo rward to ensure that California achieves its reliability, affordability, equity, and carbon reduction imperatives while recognizing the important role that technology and customer preferences will play in shaping this future.

On October 11, 2017, the CP UC announced the formation of the California Customer Choice Project to examine the issues and produce a report evaluating regulatory framework options in early 2018. The CPUC held an informal public workshop on October 31 , 2017 , to gather stakeholder inp ut on global and national electric market choice models, including California's 2020 market. The project may produce a white paper that will provide a framework to evaluate customer choice models based on affordability, decarbonization, and reliability. The white paper will not present a recommendation nor is it intended to provide the basis for instituting a rulemaking . While the CPUC had indicated its intent to open a proceeding related to customer choice, the Utility is unable to predict whether that remains the CPUC's intent or the timing of any such proceeding.

*Electric Vehicle (EV) Infrastructure Development*

In December 2014, the CPUC issued a decision adopting a policy to expand the California utilities' role in developing EV charging infrastructure to support California's climate goals. On February 9, 2015, the Utility filed an application requesting that the CPUC approve the Utility's proposal to deploy, own, and maintain EV charging stations and the associated infrastructure. On December 15, 2016, the CPUC issued a final decision establishing a three-year EV program of $130 million (approximately $109 million in capital expenditures) to deploy up to 7,500 charging stations. Further deployment of light-duty EV infrastructure will be considered in a second phase of the proceeding.

*Transportation Electrification (TE)*

California Law (SB 350) requires the CPUC, in consultation with the CARB 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. The CPUC may issue a proposed decision on the make-ready infrastructure proposals in the first or second quarter of 2018.

*Fire Safety OIR*

On December 14, 2017, the CPUC approved new regulations to enhance the fire safety of overhead electric transmission and distribution lines located in high fire-threat areas. This is the culmination of a decade-long effort to improve the fire safety of overhead utility and communication infrastructure across California. The SED conferred with Cal Fire, California IOUs, and fire safety professionals, to develop and adopt a statewide fire-threat map. This map, in conjunction with a United States Forest Service and Cal Fire map of tree mortality high hazard zones, will dictate the application of the new fire safety regulations. On January 19, 2018, the CPUC approved the final fire safety map associated with the new regulations.

The new regulations include increased patrol frequency for overhead facilities, expanded vegetation clearances around powerlines, and give the utilities increased authority to de-energize lines on private property for the removal of trees that pose an immediate threat to fire safety. The costs associated with the implementation of these new regulations will be tracked in a fire hazard prevention memorandum account and requested for recovery through rates.

**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 $CO_2$ 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 Item 1A. Risk Factors, "Environmental Regulation" in Item 1. and "Environmental Remediation Contingencies" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**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 non-trading purposes (i.e. risk mitigation) and not for speculative purposes. The Utility's risk management activities include the use of physical and financial instruments such as forward contracts, futures, swaps, options, and other instruments and agreements, most of which are accounted for as derivative instruments. Some contracts are accounted for as leases.

**Commodity Price Risk**

The Utility is exposed to commodity price risk as a result of its electricity and natural gas procurement activities, including the procurement of natural gas and nuclear fuel necessary for electricity generation and natural gas procurement for core customers. As long a s the Utility can conclude that it is probable that its reasonably incurred wholesale electricity procurement costs and natural gas costs are recoverable, fluctuations in electricity and natural gas prices will not affect earnings . Such fluctuations, howe ver, may impact cash flows. The Utility's natural gas transportation and storage costs for core customers are also fully recoverable through a ratemaking mechanism.

The Utility's current authorized revenue requirement for natural gas transportation and storage service to non-core customers is not balancing account protected. The Utility recovers these costs in its gas transmission and storage rate cases through fixed reservation charges and volumetric charges from long-term contracts, resulting in pric e and volumetric risk. The Utility uses value-at-risk to measure its shareholders' exposure to these risks. The Utility's value-at-risk was approximately $ 8 million and $7 million at December 31 , 2017 and 2016 , respectively . During 2017 , t he Utility's approximate high, low, and average values-at-risk were $8 million, $7 million and $7 million, respectively. During 2016 , the value-at-risk amounts were $7 million, $1 million and $4 million, respectively . ( See Note 9 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of price risk management activities.)

**Interest Rate Risk**

Interest rate risk sensitivity analysis is used to measure interest rate risk by computing estimated changes in cash flows as a result of assumed changes in market interest rates. A t December 31 , 2017 and 2016 , if interest rates changed by 1% for all PG&E Corporation and Utility variable rate long-term debt, short-term debt, and cash investments , th e impact on net income over the next 12 months would be $ 12 million and $13 million, respectively, based on net variable rate debt and other interest rate-sensitive instruments outstanding. ( See Note 4 of the Notes to the Consolidated Financial Statements in Item 8 for further discussion of interest rates .)

**Energy Procurement Credit Ris k**

The Utility conducts business with counterparties mainly in the energy industry, including the CAISO market, other California investor-owned electric utilities, municipal utilities, energy trading companies, financial institutions, electricity generatio n companies, and oil and natural gas production companies located in the United States and Canada. If a counterparty fails to perform on its contractual obligation to deliver electricity or gas, then the Utility may find it necessary to procure electricit y or gas at current market prices, which may be higher than the contract prices.

The Utility manages credit risk associated with its counterparties by assigning credit limits based on evaluations of their financial conditions, net worth, credit ratings, a nd other credit criteria as deemed appropriate. Credit limits and credit quality are monitored periodically. The Utility executes many energy contracts under master commodity enabling agreements that may require security (referred to as "Credit Collatera l" in the table below). Credit c ollateral may be in the form of cash or letters of credit. The Utility may accept other forms of performance assurance in the form of corporate guarantees of acceptable credit quality or other eligible securities (as deeme d appropriate by the Utility). Credit c ollateral or performance assurance may be required from counterparties when current net receivables and replacement cost exposure exceed contractually specified limits.

The following table summarizes the Utility' s energy procurement credit risk exposure to its counterparties :

| (in millions) | Gross Credit Exposure Before Credit Collateral (1) | Credit Collateral | Net Credit Exposure (2) | Number of Wholesale Customers or Counterparties >10% | Net Credit Exposure to Wholesale Customers or Counterparties >10% |
|---|---|---|---|---|---|
| De cember 31, 2017 | $ 40 | $ (16) | $ 24 | 2 | 12 |
| December 31, 2016 | $ 69 | $ (11) | $ 58 | 3 | 39 |

(1) Gross credit exposure equals mark-to-market value on physically and financially settled contracts, and net receivables (payables) where netting is contractually allowed. Gross and net credit exposure amounts reported above do not include adjustments for time value or liquidity.
(2) Net credit exposure is the Gross Credit Exposure Before Credit Collateral minus Credit Collateral (cash deposits and letters of credit posted by counterparties and held by the Utility). For purposes of this table, parental guarantees are not included as part of the calculation.

## CRITICAL ACCOUNTING POLICIES

The preparation of the Conso lidated 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 financial statements and the reported amounts of revenues and expenses durin g the reporting period. The accounting policies described below are considered to be 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 and assumptions . These accounting policies and their key characteristics are ou tlined below.

**Regulatory Accounting**

As a regulated entity, t he Utility records regulatory assets and liabilities for amounts that are deemed probable of recovery from, or refund to, customers. These amounts would otherwise be recorded to expense or income under GAAP. Refer to “Regulation and Regulated Operations” in Note 2 as well as Note 3 of the Notes to the Consolidated Financial Statements in Item 8. At December 31, 2017 , PG&E Corporation and the Utility reported regulato ry assets (including current regulatory balancing accounts receivable) of $ 5 .6 billion and regulatory liabilities (including current regulatory balancing accounts payable) of $9.9 billion .

Determining probability requires signifi cant judgment by management and includes, but is not limited to, consideration of testimony presented in regulatory hearings, proposed regulatory decisions, final regulatory orders, and the strength or status of applications for rehearing or state court ap peals. For some of the Utility’s regulatory assets, including utility retained generation , the Utility has determined that the costs are recoverable based on specific approval from the CPUC . The Utility also records a regulatory asset when a mechanism is in place to recover current expenditures and historical experience indicates that recovery of incurred costs is probable, such as the r egulatory assets for pension benefits ; deferred income tax; price risk management; and unamortized loss, net of gain, on reacquired debt. The CPUC has not denied the recovery of any material costs previously recognized by the Utility as regulatory assets for the periods presented. If the Utility determined that it is no longer probable th at regulatory assets would be reco vered or reflected in future rates, or if the Utility ceased to be subject to rate regulation, the regulatory assets would be charged against income in the period in which that determination was made. I f regulatory accounting did not apply, the Utility’s future financial results could become more volatile as compared to historical financial results due to the differences in the timing of expense or revenue recognition.

In addition, regulatory accounting standards require recognition of a loss if it beco mes probable that capital expenditures will be disallowed for ratemaking purposes and if a reasonable estimate of the amount of the disallowance can be made. Such assessments require significant judgment by management regarding probability of recovery, as described above, and the ultimate cost of construction of capital assets. The Utility records a loss to the extent capital costs are expected to exceed the amount to be recovered. The Utility records a provision based on its best estimate; to the extent t here is a high degree of uncertainty in the Utility’s forecast, it will record a provision based on the lower end of the range of possible losses. The Utility’s capital forecasts involve a series of complex judgments regarding detailed project plans, esti mates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors.

In 2017, t he Utility recorded charges of $47 million for capital expenditures related to cancelled projects and disallowed license renewal costs as part of the Diablo Canyon settlement agreement. In 2016, the Utility incurred charges of $283 million and $219 million for capital spending that wa s disallowed related to the San Bruno Penalty Decision and for capital expenditures disallowed based on the final phase two decision in its 2015 GT&S rate case, respectively. In 2015, the Utility incurred charges of $407 million for capital spending that were disallowed related to the San Bruno Penalty Decision. The Utility would be required to record charges in future periods to the extent there are additional capital disallowances. (See “ Enforcement and Litigation Matters ” in Note 1 3 of the Notes to th e Consolidated F inancial Statements in Item 8.)

**Loss Contingencies**

As discussed below, PG&E Corporation and t he Utility have recorded material accruals for various enforcement and legal matters and enviro nmental remediation liabilities.  PG& E Corporation and the Utility have also recorded insurance receivables for third-party claims.

***Enforcement and Litigation Matters***

PG&E Corporation and the Utility are subject to various laws and regulations and, in the normal course of business, are name d as parties in a number of claims and lawsuits.  In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations.  PG&E Corporation and the Utility record a provision for a loss contingency when it is both p robable that a loss has been incurred and the amount of the loss can be reasonably estimated.  PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount w ithin the range is a better estimate than any other amount.  The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events.  Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a pa rticular matter.  PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred.  Actual results may differ materially from these estimates and assumptions.  (See "Enforcement and Litig ation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

***Environmental Remediation Liabilities***

The Utility is subject to loss contingencies pursuant to federal and California environmental laws and regulations that in t he future may require the Utility to pay for environmental remediation at sites where it has been, or may be, a potentially responsible party.  Such contingencies may exist for the remediation of hazardous substances at various potential sites, including f ormer manufactured gas plant sites, power plant sites, gas compressor stations, and sites used by the Utility for the storage, recycling, or disposal of potentially hazardous materials, even if the Utility did not deposit those substances on the site.

The Utility generally commences the environmental remediation assessment process upon notification from federal or state agencies, or other parties, of a potential site requiring remedial action.  (In some instances, the Utility may initiate action to determi ne its remediation liability for sites that it no longer owns in cooperation with regulatory agencies.  For example, the Utility has begun a program related to certain former manufactured gas plant sites.)  Based on such notification, the Utility completes an assessment of the potential site and evaluates whether it is probable that a remediation liability has been incurred.  The Utility records an environmental remediation liability when site assessments indicate remediation is probable and it can reasonab ly estimate the loss or a range of possible losses .  Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for estimating remediation liabilities is subjective and requires significant judgment.  Key factors evaluated in developing cost estimates include the extent and types of hazardous substances at a potential site, the range of technologies that can be used for remediation, the determination of the Utility's liability in proportion to other responsible parties, and the extent to which such costs are recoverable from third parties.

When possible, the Utility estimates costs using site-specific information, but also considers historical experience f or costs incurred at similar sites depending on the level of information available.  Estimated costs are composed of the direct costs of the remediation effort and the costs of compensation for employees who are expected to devote a significant amount of t ime directly to the remediation effort.  These estimated costs include remedial site investigations, remediation actions, operations and maintenance activities, post remediation monitoring, and the costs of technologies that are expected to be approved to remediate the site.  Remediation efforts for a particular site generally extend over a period of several years.  During this period, the laws governing the remediation process may change, as well as site conditions, thereby possibly affecting the cost of t he remediation effort.

At December 31, 2017 and 2016 , the Utility 's accruals for undiscounted gross environmental liabilities were $ 1 b illion and $ 958 million, respectively. The Utility's undiscounted future costs c ould increase to as much as $ 2.1 billion if the extent of contamination or necessary remediation is greater than anticipated or if the other potentially responsible parties are not financially able to contribute to these costs, and could increase further if the Utility chooses to remediate beyond regulatory requirements. Although the Utility has provided for known environmenta l obligations that are probable and reasonably estimable, estimated costs may vary significantly from actual costs, and the amount of additional future costs may be material to results of operations in the period in which they are recognized.

***Insurance Receivable***

The Utility has liability insurance from various insurers, which provides coverage for third party claims. The Utility records insurance recoveries only when a third party claim is recorded and it is deemed probable that a recovery of that claim will occur and the Utility can reasonably estimate the amount or its range. The assessment of whether recovery is probable or reasonably possible, and whether the recovery or a range of recoveries is estimable, often involves a series of complex ju dgments about future events. Insurance recoveries are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, including contractual liability insurance policy coverage, advice of legal counsel, past experience with si milar events, discussions with insurers and other information and events pertaining to a particular matter. (See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

**Asset Retirement Obligation s**

PG&E Corporation and the Utility account for an ARO at fair value in the period during which the legal obligation is incurred if a reasonable estimate of fair value and its settlement date can be made. At the time of recording an ARO, the associated as set retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognize s a regulatory asset or liabilit y for the timing differences between the recognition of expenses and costs recovered through the rate making process. (See Notes 2 and 3 of the Notes to the Consolidated Financial Statements in Item 8.)

To estimate its liability, the Utility uses a discounted cash flow model based upon significant est imates and assumptions abou t future decommissioning costs, inflation rates, and the estimated date of decommissioning. The estimated future cash flows are discounted using a credit-adjusted risk-free rate that reflects the risk associated with the decommissioning obligation.

At December 31, 2017 , the Utility's recorded ARO for the estimated cost of retiring these long-lived assets was $ 4.9 billion . Changes in these estimates and assumptions could materially affect the amount of the recorded ARO for these assets.

**Pension and Other Postretirement Benefit Plans**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible emplo yees a s well as contributory postretirement health care and medical plans for eligible r etirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees . Adjustments to the pension and oth er benefit obligation are based on the d ifferences between actuarial assumptions and actual plan results . These amounts are deferred in accumulated other comprehensive income (loss) and amortized into income on a gradual basis. The differences between pe nsion benefit expense recognized in accordance with GAAP and amounts recognized for ratem aking purposes are recorded as regulatory asset s or liabilit ies as amounts are probable of recovery from customers. To the extent the other benefits are in an overfun ded position, the Utility records a regulatory liability. (See Note 3 of the Notes to the Consolidated Financial Statements in Item 8.)

The pension and other postretirement benefit obligations are calculated using actuarial models as of the December 31 measurement date. The significant a ctuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost tre nd rate and the expected return on plan assets. PG&E Corporation and the Utility review these assumptions on an annual basis and adjust them as necessary . While PG&E Corporation and the Utility believe that the assumptions used are appropriate, significa nt differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit oblig ations and future plan expenses.

I n establishing health care cost ass umptions, PG&E Corporation and the Utility consider rec ent cost trends and projections from industry experts . This evaluation suggests that current rates of inflation are expected to continue in the near term. In recognition of continued high inflation i n health care costs and given the design of PG&E Corporation's plans, the assumed health care cost trend rate for 2018 is 6.8 % , gradually decreasing to the u ltimate trend rate of 4.5 % in 2027 and beyond .

Expected rates of return on plan assets were developed by estimating future stock and bond returns and then applying these returns to the target asset allocations of the employee benefit trusts, resulting in a weighted average rate of return on plan assets. Fixed - income returns were projected based on real maturity and credit sp reads added to a long-term inflat ion rate. Equity returns were projected based on estimates of dividend yield and real earnings growth added to a long-term rate of inflation. For the Utility's defined benefit pension plan, the assumed return of 6.2 % compares to a ten-year actual return of 7.8 % .

The rate used to discount pension benefits and other benefits was based on a yield curve developed from market data of approximately 623 Aa-grade non-callable bonds at December 31, 2017 . This yield curve has discount rates that vary based on the duration of the obligations. The estimated futu re cash flows for the pension and other postretirement benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average discount rate.

The following reflects the sensitivity of pension costs and projected benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2017 Pension Costs | Increase in Projected Benefit Obligation at December 31, 2017 |
|---|---|---|---|
| Discount rate | (0.50) % | $ 111 | $ 1,485 |
| Rate of return on plan assets | (0.50) % | 73 | - |
| Rate of increase in compensation | 0.50 % | 61 | 348 |

The following reflects the sensitivity of other postretirement benefit costs and accumulated benefit obligation to changes in certain actuarial assumptions:

| (in millions) | Increase (Decrease) in Assumption | Increase in 2017 Other Postretirement Benefit Costs | Increase in Accumulated Benefit Obligation at December 31, 2017 |
|---|---|---|---|
| Health care cost trend rate | 0.50 % | $ 4 | $ 63 |
| Discount rate | (0.50) % | 4 | 142 |
| Rate of return on plan assets | (0.50) % | 10 | - |

**NEW ACCOUNTING PRONOUNCEMENTS**

See Note 2 of the Notes to the Consolidated Financial Statements.

**FORWARD-LOOKING STATEMENTS**

This report contains forward-looking statements that are necessarily subject to various risks and uncertainties. These statements reflect management's judgment and opinions which are based on current estimates, expectations, a nd 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 tho se 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," "anticipate," "may," "should," "would," "could," "potential" and similar expressions. PG&E Corporation and the Utility are not able to predict all the factors that may affect futu re 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 wi ldfires, including the costs of restoration of service to customers and repairs to the Utility's facilities, and whether the Utility is able to recover such costs through CEMA; the timing and outcome of the wildfire investigations , includin g into the cause s 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 mechanis ms, 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 tha t the Utility failed to comply with applicable laws and regulation s;

- the impact of the Tax Act, and the timing and outcome of the CPUC decision related to the Utility's future filings in connection with the impact of the Tax Act on the Utility's rate cases and its implementation plan;

- t he Utility's ability to efficiently manage capital expenditures and its operating and maintenance expenses within the authorized levels of spending and timely recover its costs through rates, and the extent to which t he Utility incurs unrecoverable costs that are higher than the forecasts of such costs;

- the timing and outcomes of the 2019 GT&S rate case, TO 18 and TO19 rate case s and other ratemaking and regulatory proceedings;

- the timing and outcome of the Butte fire litigation, the timing and outcome of any proceeding to recover costs in excess of insurance from customers, 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 litigati on; 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 wildf ire 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 outcome of the probation and the monitorship im posed 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 law s 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 reme dial costs that the Utility may incur in connection with the outcomes;

- the timing and outcomes of investigations by t he U.S. Attorney's Office in San Francisco and the California Attorney General's office related to communications between the Utility's pe rsonnel 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 is sued in the Utility's ratemaking proceedings ;

- the effects on P G&E Corporation and the Utility's reputations caused by the Utility's conviction in the federal criminal trial in 2017 , the state and federal investigations of natural gas incidents and the Nor thern 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 successfully implement 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 is able to successfully adapt its business model to significant change that the electric industry is undergoin g and the impact such change will have on the natural gas industry;

- the impact of increased costs to comply with natural gas regulations, including the SB 887 directing DOGGR and CARB to develop permanent regulations for gas storage facility operations in California to comply with new safety and reliability measures, the PHMSA rules effective January 18, 2017 regulating gas storage facilities at the federal level; and the CPUC General Order 112-F that went into effect on January 1, 2017, that requires addi tional expenditures in the areas of gas leak repair, leak survey, high consequences area identification, and operator qualifications, and could impact the Utility's ability to timely recover such costs;

- wh ether 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 C A ISO’s Transmission Planning Process to allow for greater participat ion 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 C AISO 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 t o 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 regul atory actions tha t 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 an d 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, includin g the construction, expansion or replacement of its electric and gas facilities, electric grid reliability, inspection and maintenance practices, customer billing and privacy, physical and cyber security, env ironmental laws and regulations; and the outcome of notices of violations in connection with the Yuba City incident;

- the outcomes of the CPUC’s data requests and future PDs, including in connection with the Utility’s S martMeter™ Upgrade cost-benefit analysis, and of the Utility’s PFMs, including in con nection with the installation of new cathodic protection systems in 2018;

- 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; an d the extent to which the Utility is able to recover environmental costs in rates or from other sources;

- the ultimate amount of unrecoverable environmental costs the Utility incurs associated with the Utility’s natural gas compressor station site located near Hinkley, California;

- the impact of new legislation or NRC regulations, recommendations, policies, decisions, or orders relating to the nuclear industry, including operations, seismic design, security, safety, relicensing, the storage of spent nuclear fuel, decommissioning, cooling water intake, or other issues; the impact of actions taken by state agencies that may affect the Utility's ability to continue operating Diablo Canyon; whether the Utility will be able to successfully implement its retention and retraining and development progr ams 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 condition s 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 regul atory 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 breakdown or failure of equipment that can cause fires and unplanned o utages; and whether the Utility will be subject to investigations, penalties, and other costs in connection with such events;

- how the CPUC and the CARB implement state environmental laws relating to GHG, renewable energy targets, energy efficiency st anda rds, 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 re cover 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 investme nts 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 inc reasing 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 it s renewable energy procurement costs;

- whether, as a result of Westinghouse's Chapter 11 proceeding and its planned purchase by Brookfield Business Partners L.P., the Utility will experience issues with nuclear fuel supply, nuclear fuel inventory, and rela ted services and products that Westinghouse supplies, and whether such proceeding 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 in curred in connection with third-party claims or litigation can be recovered through insurance, rates, or from other third parties; and whether the Utility can continue to obtain adequate insurance coverage for future losses or claims, especially following a major event that causes widespread third-party losses;

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

- changes in credit ratings which could , 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 federal or state laws or regulations, or their interp retation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the Utility 's conviction in the federal criminal trial , and other enforcement matters will impact the Utility's ability to make distributions to PG&E Corporation, and, in turn, PG&E Corporation's ability to pay dividends;

- the outcome of federal or state tax audits and the impact of any changes in federal or state tax laws, policies, regulations, or their interpretation;
- changes in the regulatory and economic environment, including potential chang es affecting renewable energy sources and associated tax credits, as a result of the new 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.

For more information about the significant risks that could affect the outcome of the forward-looking statements and PG&E Corporation's and the Utility's future financial condition, results of operations, and cash f lows, see Item 1A. Risk Factors below and a detailed discussion of these matters contained elsewhere in MD&A. PG&E Corporation and the Utility do not undertake any obligation to update forward-looking statements, whether in response to new information, fut ure 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 su ch 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 th is 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 act ive 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 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

Information responding to Item 7A is set forth under the heading "Risk Management Activities," in Item 7. MD &A and in Note 9: Derivatives and Note 10: Fair Value Measurements of the Notes to the Consolidated Financial Statements in Item 8.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions, except per share amounts)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Operating Revenues** | | | |
| Electric | $ 13,124 | $ 13,864 | $ 13,657 |
| Natural gas | 4,011 | 3,802 | 3,176 |
| **Total operating revenues** | **17,135** | **17,666** | **16,833** |
| **Operating Expenses** | | | |
| Cost of electricity | 4,309 | 4,765 | 5,099 |
| Cost of natural gas | 746 | 615 | 663 |
| Operating and maintenance | 6,270 | 7,354 | 6,951 |
| Depreciation, amortization, and decommissioning | 2,854 | 2,755 | 2,612 |
| **Total operating expenses** | **14,179** | **15,489** | **15,325** |
| **Operating Income** | 2,956 | 2,177 | 1,508 |
| Interest income | 31 | 23 | 9 |
| Interest expense | (888) | (829) | (773) |
| Other income, net | 72 | 91 | 117 |
| **Income Before Income Taxes** | **2,171** | **1,462** | **861** |
| Income tax provision (benefit) | 511 | 55 | (27) |
| **Net Income** | **1,660** | **1,407** | **888** |
| **Preferred stock dividend requirement of subsidiary** | 14 | 14 | 14 |
| **Income Available for Common Shareholders** | **$ 1,646** | **$ 1,393** | **$ 874** |
| **Weighted Average Common Shares Outstanding, Basic** | **512** | **499** | **484** |
| **Weighted Average Common Shares Outstanding, Diluted** | **513** | **501** | **487** |
| **Net Earnings Per Common Share, Basic** | **$ 3.21** | **$ 2.79** | **$ 1.81** |
| **Net Earnings Per Common Share, Diluted** | **$ 3.21** | **$ 2.78** | **$ 1.79** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E C orporation**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Net Income** | **$ 1,660** | **$ 1,407** | **$ 888** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0, $1, and $0, at respective dates) | 1 | (2) | (1) |
| Net change in investments (net of taxes of $0, $0, and $12 at respective dates) | - | - | (17) |
| **Total other comprehensive income (loss)** | **1** | **(2)** | **(18)** |
| **Comprehensive Income** | **1,661** | **1,405** | **870** |
| **Preferred stock dividend requirement of subsidiary** | **14** | **14** | **14** |
| **Comprehensive Income Attributable to Common Shareholders** | **$ 1,647** | **$ 1,391** | **$ 856** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2017** | **2016** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 449 | $ 177 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $64 and $58 at respective dates) | 1,243 | 1,252 |
| Accrued unbilled revenue | 946 | 1,098 |
| Regulatory balancing accounts | 1,222 | 1,500 |
| Other | 861 | 801 |
| Regulatory assets | 615 | 423 |
| Inventories | | |
| Gas stored underground and fuel oil | 115 | 117 |
| Materials and supplies | 366 | 346 |
| Income taxes receivable | - | 160 |
| Other | 464 | 290 |
| **Total current assets** | **6,281** | **6,164** |
| **Property, Plant, and Equipment** | | |
| Electric | 55,133 | 52,556 |
| Gas | 19,641 | 17,853 |
| Construction work in progress | 2,471 | 2,184 |
| Other | 3 | 2 |
| **Total property, plant, and equipment** | **77,248** | **72,595** |
| Accumulated depreciation | (23,459) | (22,014) |
| **Net property, plant, and equipment** | **53,789** | **50,581** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 3,793 | 7,951 |
| Nuclear decommissioning trusts | 2,863 | 2,606 |
| Income taxes receivable | 65 | 70 |
| Other | 1,221 | 1,226 |
| **Total other noncurrent assets** | **7,942** | **11,853** |
| **TOTAL ASSETS** | **$ 68,012** | **$ 68,598** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED BALANCE SHEETS**
**(in millions, except share amounts)**

| | Balance at December 31, | |
|---|---|---|
| | **2017** | **2016** |
| **LIABILITIES AND EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 931 | $ 1,516 |
| Long-term debt, classified as current | 445 | 700 |
| Accounts payable | | |
| Trade creditors | 1,646 | 1,495 |
| Regulatory balancing accounts | 1,120 | 645 |
| Other | 517 | 433 |
| Disputed claims and customer refunds | 243 | 236 |
| Interest payable | 217 | 216 |
| Other | 2,010 | 2,323 |
| **Total current liabilities** | **7,129** | **7,564** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 17,753 | 16,220 |
| Regulatory liabilities | 8,679 | 6,805 |
| Pension and other postretirement benefits | 2,128 | 2,641 |
| Asset retirement obligations | 4,899 | 4,684 |
| Deferred income taxes | 5,822 | 10,213 |
| Other | 2,130 | 2,279 |
| **Total noncurrent liabilities** | **41,411** | **42,842** |
| **Commitments and Contingencies (Note 13)** | | |
| **Equity** | | |
| **Shareholders' Equity** | | |
| Common stock, no par value, authorized 800,000,000 shares; 514,755,845 and 506,891,874 shares outstanding at respective dates | 12,632 | 12,198 |
| Reinvested earnings | 6,596 | 5,751 |
| Accumulated other comprehensive loss | (8) | (9) |
| **Total shareholders' equity** | **19,220** | **17,940** |
| **Noncontrolling Interest - Preferred Stock of Subsidiary** | 252 | 252 |
| **Total equity** | **19,472** | **18,192** |
| **TOTAL LIABILITIES AND EQUITY** | **$ 68,012** | **$ 68,598** |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 1,660 | $ 1,407 | $ 888 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,854 | 2,755 | 2,612 |
| Allowance for equity funds used during construction | (89) | (112) | (107) |
| Deferred income taxes and tax credits, net | 1,254 | 1,030 | 693 |
| Disallowed capital expenditures | 47 | 507 | 407 |
| Other | 307 | 379 | 326 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | 67 | (473) | (177) |
| Butte-related insurance receivable | (21) | (575) | - |
| Inventories | (18) | (24) | 37 |
| Accounts payable | 173 | 180 | (55) |
| Butte-related third-party claims | (129) | 690 | - |
| Income taxes receivable/payable | 160 | (5) | 43 |
| Other current assets and liabilities | 42 | 83 | (288) |
| Regulatory assets, liabilities, and balancing accounts, net | (387) | (1,214) | (244) |
| Other noncurrent assets and liabilities | 57 | (219) | (355) |
| **Net cash provided by operating activities** | **5,977** | **4,409** | **3,780** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,641) | (5,709) | (5,173) |
| Decrease in restricted cash | - | 227 | 64 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,291 | 1,295 | 1,268 |
| Purchases of nuclear decommissioning trust investments | (1,323) | (1,352) | (1,392) |
| Other | 23 | 13 | 22 |
| **Net cash used in investing activities** | **(5,650)** | **(5,526)** | **(5,211)** |
| **Cash Flows from Financing Activities** | | | |
| Net issuances (repayments) of commercial paper, net of discount of $5, $6, and $3 at respective dates | (840) | (9) | 683 |
| Short-term debt financing | 750 | 500 | - |
| Short-term debt matured | (500) | - | (300) |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $32, $17 and $27 at respective dates | 2,713 | 983 | 1,123 |
| Long-term debt matured or repurchased | (1,445) | (160) | - |
| Common stock issued | 395 | 822 | 780 |
| Common stock dividends paid | (1,021) | (921) | (856) |
| Other | (107) | (44) | (27) |
| **Net cash provided by financing activities** | **(55)** | **1,171** | **1,403** |
| **Net change in cash and cash equivalents** | **272** | **54** | **(28)** |
| **Cash and cash equivalents at January 1** | **177** | **123** | **151** |
| **Cash and cash equivalents at December 31** | **$ 449** | **$ 177** | **$ 123** |

| | | | |
|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (790) | $ (726) | $ (684) |
| Income taxes, net | 162 | 231 | 77 |
| **Supplemental disclosures of noncash investing and financing activities** | | | |
| Common stock dividends declared but not yet paid | $ - | $ 248 | $ 224 |
| Capital expenditures financed through accounts payable | 501 | 403 | 440 |
| Noncash common stock issuances | 21 | 20 | 21 |
| Terminated capital leases | 23 | 18 | - |

See accompanying Notes to the Consolidated Financial Statements.

**PG&E Corporation**
**CONSOLIDATED STATEMENTS OF EQUITY**
**(in millions, except share amounts)**

| | Common Stock Shares | Common Stock Amount | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity | Non controlling Interest - Preferred Stock of Subsidiary | Total Equity |
|---|---|---|---|---|---|---|---|
| **Balance at December 31, 2014** | **475,913,404** | **$ 10,421** | **$ 5,316** | **$ 11** | **$ 15,748** | **$ 252** | **$ 16,000** |
| Net income | - | - | 888 | - | 888 | - | 888 |
| Other comprehensive loss | - | - | - | (18) | (18) | - | (18) |
| Common stock issued, net | 16,112,039 | 801 | - | - | 801 | - | 801 |
| Stock-based compensation amortization | - | 66 | - | - | 66 | - | 66 |
| Common stock dividends declared | - | - | (889) | - | (889) | - | (889) |
| Tax expense from employee stock plans | - | (6) | - | - | (6) | - | (6) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2015** | **492,025,443** | **$ 11,282** | **$ 5,301** | **$ (7)** | **$ 16,576** | **$ 252** | **$ 16,828** |
| Cumulative effect of change in accounting principle | - | - | 29 | - | 29 | - | 29 |
| Net income | - | - | 1,407 | - | 1,407 | - | 1,407 |
| Other comprehensive loss | - | - | - | (2) | (2) | - | (2) |
| Common stock issued, net | 14,866,431 | 842 | - | - | 842 | - | 842 |
| Stock-based compensation amortization | - | 74 | - | - | 74 | - | 74 |
| Common stock dividends declared | - | - | (972) | - | (972) | - | (972) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2016** | **506,891,874** | **$ 12,198** | **$ 5,751** | **$ (9)** | **$ 17,940** | **$ 252** | **$ 18,192** |
| Net income | - | - | 1,660 | - | 1,660 | - | 1,660 |
| Other comprehensive income | - | - | - | 1 | 1 | - | 1 |
| Common stock issued, net | 7,863,971 | 416 | - | - | 416 | - | 416 |
| Stock-based compensation amortization | - | 18 | - | - | 18 | - | 18 |
| Common stock dividends declared | - | - | (801) | - | (801) | - | (801) |
| Preferred stock dividend requirement of subsidiary | - | - | (14) | - | (14) | - | (14) |
| **Balance at December 31, 2017** | **514,755,845** | **$ 12,632** | **$ 6,596** | **$ (8)** | **$ 19,220** | **$ 252** | **$ 19,472** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Operating Revenues** | | | |
| Electric | $ 13,127 | $ 13,865 | $ 13,657 |
| Natural gas | 4,011 | 3,802 | 3,176 |
| **Total operating revenues** | **17,138** | **17,667** | **16,833** |
| **Operating Expenses** | | | |
| Cost of electricity | 4,309 | 4,765 | 5,099 |
| Cost of natural gas | 746 | 615 | 663 |
| Operating and maintenance | 6,329 | 7,352 | 6,949 |
| Depreciation, amortization, and decommissioning | 2,854 | 2,754 | 2,611 |
| **Total operating expenses** | **14,238** | **15,486** | **15,322** |
| **Operating Income** | 2,900 | 2,181 | 1,511 |
| Interest income | 30 | 22 | 8 |
| Interest expense | (877) | (819) | (763) |
| Other income, net | 65 | 88 | 87 |
| **Income Before Income Taxes** | **2,118** | **1,472** | **843** |
| Income tax provision (benefit) | 427 | 70 | (19) |
| **Net Income** | **1,691** | **1,402** | **862** |
| Preferred stock dividend requirement | 14 | 14 | 14 |
| **Income Available for Common Stock** | **$ 1,677** | **$ 1,388** | **$ 848** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Net Income** | **$ 1,691** | **$ 1,402** | **$ 862** |
| **Other Comprehensive Income** | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $3, $1, and $1, at respective dates) | 4 | (1) | (2) |
| **Total other comprehensive income (loss)** | **4** | **(1)** | **(2)** |
| **Comprehensive Income** | **$ 1,695** | **$ 1,401** | **$ 860** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions)**

| | Balance at December 31, | |
|---|---|---|
| | **2017** | **2016** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 447 | $ 71 |
| Accounts receivable | | |
| Customers (net of allowance for doubtful accounts of $64 and $58 at respective dates) | 1,243 | 1,252 |
| Accrued unbilled revenue | 946 | 1,098 |
| Regulatory balancing accounts | 1,222 | 1,500 |
| Other | 862 | 801 |
| Regulatory assets | 615 | 423 |
| Inventories | | |
| Gas stored underground and fuel oil | 115 | 117 |
| Materials and supplies | 366 | 346 |
| Income taxes receivable | - | 159 |
| Other | 465 | 289 |
| **Total current assets** | **6,281** | **6,056** |
| **Property, Plant, and Equipment** | | |
| Electric | 55,133 | 52,556 |
| Gas | 19,641 | 17,853 |
| Construction work in progress | 2,471 | 2,184 |
| **Total property, plant, and equipment** | **77,245** | **72,593** |
| Accumulated depreciation | (23,456) | (22,012) |
| **Net property, plant, and equipment** | **53,789** | **50,581** |
| **Other Noncurrent Assets** | | |
| Regulatory assets | 3,793 | 7,951 |
| Nuclear decommissioning trusts | 2,863 | 2,606 |
| Income taxes receivable | 64 | 70 |
| Other | 1,094 | 1,110 |
| **Total other noncurrent assets** | **7,814** | **11,737** |
| **TOTAL ASSETS** | **$ 67,884** | **$ 68,374** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED BALANCE SHEETS**
**(in millions , except share amounts )**

| | Balance at December 31, | |
|---|---|---|
| | **2017** | **2016** |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 799 | $ 1,516 |
| Long-term debt, classified as current | 445 | 700 |
| Accounts payable | | |
| Trade creditors | 1,644 | 1,494 |
| Regulatory balancing accounts | 1,120 | 645 |
| Other | 538 | 453 |
| Disputed claims and customer refunds | 243 | 236 |
| Interest payable | 214 | 214 |
| Other | 2,018 | 2,072 |
| **Total current liabilities** | **7,021** | **7,330** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 17,403 | 15,872 |
| Regulatory liabilities | 8,679 | 6,805 |
| Pension and other postretirement benefits | 2,026 | 2,548 |
| Asset retirement obligations | 4,899 | 4,684 |
| Deferred income taxes | 5,963 | 10,510 |
| Other | 2,146 | 2,230 |
| **Total noncurrent liabilities** | **41,116** | **42,649** |
| **Commitments and Contingencies (Note 13)** | | |
| **Shareholders' Equity** | | |
| Preferred stock | 258 | 258 |
| Common stock, $5 par value, authorized 800,000,000 shares; 264,374,809 shares outstanding at respective dates | 1,322 | 1,322 |
| Additional paid-in capital | 8,505 | 8,050 |
| Reinvested earnings | 9,656 | 8,763 |
| Accumulated other comprehensive income | 6 | 2 |
| **Total shareholders' equity** | **19,747** | **18,395** |
| **TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY** | **$ 67,884** | **$ 68,374** |

See accompanying Notes to the Consolidated Financial Statements.

**Pacific Gas and Electric Company**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Cash Flows from Operating Activities** | | | |
| Net income | $ 1,691 | $ 1,402 | $ 862 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Depreciation, amortization, and decommissioning | 2,854 | 2,754 | 2,611 |
| Allowance for equity funds used during construction | (89) | (112) | (107) |
| Deferred income taxes and tax credits, net | 1,103 | 1,042 | 714 |
| Disallowed capital expenditures | 47 | 507 | 407 |
| Other | 283 | 306 | 263 |
| Effect of changes in operating assets and liabilities: | | | |
| Accounts receivable | 66 | (475) | (177) |
| Butte-related insurance receivable | (21) | (575) | - |
| Inventories | (18) | (24) | 37 |
| Accounts payable | 173 | 179 | (2) |
| Butte-related third-party claims | (129) | 690 | - |
| Income taxes receivable/payable | 159 | (29) | 38 |
| Other current assets and liabilities | 59 | 112 | (315) |
| Regulatory assets, liabilities, and balancing accounts, net | (390) | (1,214) | (244) |
| Other noncurrent assets and liabilities | 128 | (219) | (340) |
| **Net cash provided by operating activities** | **5,916** | **4,344** | **3,747** |
| **Cash Flows from Investing Activities** | | | |
| Capital expenditures | (5,641) | (5,709) | (5,173) |
| Decrease in restricted cash | - | 227 | 64 |
| Proceeds from sales and maturities of nuclear decommissioning trust investments | 1,291 | 1,295 | 1,268 |
| Purchases of nuclear decommissioning trust investments | (1,323) | (1,352) | (1,392) |
| Other | 23 | 13 | 22 |
| **Net cash used in investing activities** | **(5,650)** | **(5,526)** | **(5,211)** |
| **Cash Flows from Financing Activities** | | | |
| Net issuances (repayments) of commercial paper, net of discount of $5, $6, and $3 at respective dates | (972) | (9) | 683 |
| Short-term debt financing | 750 | 500 | - |
| Short-term debt matured | (500) | - | (300) |
| Proceeds from issuance of long-term debt, net of premium, discount and issuance costs of $32, $17, and $27 at respective dates | 2,713 | 983 | 1,123 |
| Repayments of long-term debt | (1,445) | (160) | - |
| Preferred stock dividends paid | (14) | (14) | (14) |
| Common stock dividends paid | (784) | (911) | (716) |
| Equity contribution from PG&E Corporation | 455 | 835 | 705 |
| Other | (93) | (30) | (13) |
| **Net cash provided by financing activities** | **110** | **1,194** | **1,468** |
| **Net change in cash and cash equivalents** | **376** | **12** | **4** |
| **Cash and cash equivalents at January 1** | **71** | **59** | **55** |
| **Cash and cash equivalents at December 31** | **$ 447** | **$ 71** | **$ 59** |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Supplemental disclosures of cash flow information** | | | | | | |
| Cash received (paid) for: | | | | | | |
| Interest, net of amounts capitalized | $ | (781) | $ | (717) | $ | (675) |
| Income taxes, net | | 162 | | 244 | | 77 |
| **Supplemental disclosures of noncash investing and financing activities** | | | | | | |
| Capital expenditures financed through accounts payable | $ | 501 | $ | 403 | $ | 440 |
| Terminated capital leases | | 23 | | 18 | | - |

See accompanying Notes to the Consolidated Financial Statements.

## Pacific Gas and Electric Company
## CONSOLIDATED STATEMENTS OF SHAREHOLDERS ' EQUITY
## (in millions)

| | Preferred Stock | Common Stock | Additional Paid-in Capital | Reinvested Earnings | Accumulated Other Comprehensive Income (Loss) | Total Shareholders' Equity |
|---|---|---|---|---|---|---|
| **Balance at December 31, 2014** | **$ 258** | **$ 1,322** | **$ 6,514** | **$ 8,130** | **$ 5** | **$ 16,229** |
| Net income | - | - | - | 862 | - | 862 |
| Other comprehensive loss | - | - | - | - | (2) | (2) |
| Equity contribution | - | - | 705 | - | - | 705 |
| Tax expense from employee stock plans | - | - | (4) | - | - | (4) |
| Common stock dividend | - | - | - | (716) | - | (716) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2015** | **$ 258** | **$ 1,322** | **$ 7,215** | **$ 8,262** | **$ 3** | **$ 17,060** |
| Cumulative effect of change in accounting principle | - | - | - | 24 | - | 24 |
| Net income | - | - | - | 1,402 | - | 1,402 |
| Other comprehensive loss | - | - | - | - | (1) | (1) |
| Equity contribution | - | - | 835 | - | - | 835 |
| Common stock dividend | - | - | - | (911) | - | (911) |
| Preferred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2016** | **$ 258** | **$ 1,322** | **$ 8,050** | **$ 8,763** | **$ 2** | **$ 18,395** |
| Net income | - | - | - | 1,691 | - | 1,691 |
| Other comprehensive income | - | - | - | - | 4 | 4 |
| Equit y contribution | - | - | 455 | - | - | 455 |
| Common stock dividend | - | - | - | (784) | - | (784) |
| Prefe rred stock dividend | - | - | - | (14) | - | (14) |
| **Balance at December 31, 2017** | **$ 258** | **$ 1,322** | **$ 8,505** | **$ 9,656** | **$ 6** | **$ 19,747** |

See accompanying Notes to the Consolidated Financial Statements.

## NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

### 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 is a combined annual report of PG&E Corporation and the Utility. PG&E Corporation's Consolidated Financial Statements include the accounts of PG&E Corporation, the Utility, and other wholly owned and controlled subsidiaries. The Utility's 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 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 Consolidated Financial Statements have been prepared in conformity with GAAP and in accordance with the reporting requirements of Form 10-K. The preparation of financial statements in conformity with GAAP requires the use of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities. Some of the more significant estimates and assumptions relate to the Utility's regulatory assets and liabilities, legal and regulatory contingencies, environmental remediation liabilities, AROs, and pension and other postretirement benefit plans obligations. Management believes that its estimates and assumptions reflected in the Consolidated Financial Statements are appropriate and reasonable. A change in management's estimates or assumptions could result in an adjustment that could have a material impact on PG&E Corporation's and the Utility's financial condition and results of operations and cash flows 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 California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44. The fires are being investigated by Cal Fire and the CPUC, including the possible role of the Utility's power lines and other facilities. See "Northern California Wildfires" in Note 13 below.

### NOTE 2: SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

**Regulation and Regulated Operations**

The Utility follows accounting principles for rate-regulated entities and collects rates from customers to recover "revenue requirements" that have been authorized by the CPUC or the FERC based on the Utility's cost of providing service. The Utility also records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for nonregulated entities. The Utility capitalizes and records as regulatory assets, costs that would otherwise be charged to expense if it is probable that the incurred costs will be recovered in future rates. Regulatory assets are amortized over the future periods in which the costs are recovered. If costs expected to be incurred in the future are currently being recovered through rates, the Utility records those expected future costs as regulatory liabilities. Amounts that are probable of being credited or refunded to customers in the future are also recorded as regulatory liabilities.

Management continues to believe the use of regulatory accounting is applicable and that all regulatory assets and liabilities are recoverable or refundable. To the extent that portions of the Utility's operations cease to be subject to cost of service rate regulation, or recovery is no longer probable as a result of changes in regulation or other reasons, the related regulatory assets and liabilities are written off.

**Revenue Recognition**

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 rece ivable on the Consolidated Balance Sheets. Rates charged to customers are based on CPUC and FERC authorized revenue requirements.

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. T he Utility's ability to recover r evenue requirements authorized by the CPUC in these rates cases is independent, or "decoupled" from the volume of the Utility's sales of electricity and natural gas services. The U tility 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, revenue is recognized ratably over the year. The Utility records a balan cing 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 t hat 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 pa ss-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 thos e costs , t o the extent that these differences are probable of recovery or refund . These differences have no impact on net income.

The FERC authorizes the Utility's revenue requirements in periodic (often annual) TO rate cases. The Utility's ability t o 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 .

**C ash and Cash Equivalents**

Cash and cas h equivalents consist of cash and short-term, highly liquid investments with original maturities of three months or less. Cash equivalents are stated at fair value.

**Allowance for Doubtful Accounts Receivable**

PG&E Corporation and the Utility recognize an allowance for doubtful accounts to record uncollectable customer accounts receivable at estimated net realizable value. The allowance is determined based upon a variety of factors, including historical write-off experience, aging of receivables , curren t economic conditions, and assessment of customer collectability.

**Inventories**

Inventories are carried at weighted- average cost and include natural gas stored underground as well as materials and supplies . Natural gas stored underground is recorded to inventory when injected and then expensed as the gas is withdrawn for distribut ion to customers or to be used as fuel for electric generation. Materials and supplies are recorded to inventory when purchased and expensed or capitalized to plant, as appropr iate, when consumed or installed.

**Emission Allowances**

The Utility purchases GHG emission allowances to satisfy its compliance obligations. Associated costs are recorded as inventory and included in current assets – other and other noncurrent assets – ot her on the Consolidated Balance Sheets. Costs are carried at weighted-average and are recoverable through rates.

**Property, Plant, and Equipment**

Property, plant, and equipment are reported at the lower of their historical cost less accumulated depreciat ion or fair value . Historical costs include labor and materials, construction overhead, and AFUDC. (See "AFUDC" below.) The Utility's total estimated useful lives and balances of its property, plant, and equipment were as follows:

| (in millions, except estimated useful lives) | Estimated Useful Lives (years) | Balance at December 31, 2017 | 2016 |
|---|---|---|---|
| Electricity generating facilities [1] | 5 to 120 | $ 11,843 | $ 11,308 |
| Electricity distribution facilities | 15 to 65 | 31,110 | 29,836 |
| Electricity transmission facilities | 15 to 75 | 12,180 | 11,412 |
| Natural gas distribution facilities | 5 to 60 | 12,312 | 11,362 |
| Natural gas transmission and storage facilities | 5 to 62 | 7,329 | 6,491 |
| Construction work in progress | | 2,471 | 2,184 |
| **Total property, plant, and equipment** | | **77,245** | **72,593** |
| Accumulated depreciation | | (23,456) | (22,012) |
| **Net property, plant, and equipment** | | **$ 53,789** | **$ 50,581** |

[1] Balance includes nuclear fuel inventories. Stored nuclear fuel inventory is stated at weighted- average cost. Nuclear fuel in the reactor is expensed as used based on the amount of energy output. (See Note 13 below.)

The Utility depreciates property, plant, and equipment using the composite, or group, method of depreciation, in which a single depreciation rate is applied to the gross investment balance in a particular class of property. This method approximates the straight line method of depreciation over the useful lives of property, plant, and equipment. The Utility's co mposite depreciatio n rates were 3.83 % in 2017 , 3.73% in 2016 , and 3.80 % in 2015 . The useful lives of the Utility's property, plant, and equipment are authorized by the CPUC and the FERC, and the depreciation expense is recovered through rates charged to customers. Depreciation expense includes a component for the original cost of assets and a component for estimated cost of fut ure removal, net of any salvage value at retirement. Upon retirement, the original cost of the retired assets, net of salvage value, is charged against accumulated depreciation. The cost of repairs and maintenance, including planned major maintenance act ivities and minor replacements of property, is charged to operating and maintenance expense as incurred.

**AFUDC**

AFUDC represents the estimated cost s of debt (i.e., interest) and equity funds used to finance regulated plant additions before they go into service and is capitalized as part of the cost of construction. AFUDC is recoverable from customers through rates over the life of the related property once the property is placed in service. AFUDC related to the cost of debt is recor ded as a reduction to interest expense. AFUDC related to the cost of equity is recorded in other income. The Utility recorded AFUDC related to debt and equity, respectively, of $ 38 million and $ 89 mil lion during 2017, $ 51 million and $ 112 million during 2016 , and $ 48 million and $107 million during 2015.

**Asset Retirement Obligations**

The following table summarizes the changes in ARO liability during 2017 and 2016 , including nuclear decommissioning obligations :

| (in millions) | 2017 | 2016 |
|---|---|---|
| ARO liability at beginning of year | $ 4,684 | $ 3,643 |
| Revision in estimated cash flows | 128 | 968 |
| Accretion | 207 | 194 |
| Liabilities settled | (120) | (121) |
| **ARO liability at end of year** | **$ 4,899** | **$ 4,684** |

The Utility has not recorded a liability related to certain ARO's for assets that are expe cted to operate in perpetuity. As t he Utility cannot estimate a settlement date or range of potential settlement dates for these assets , reasonable estimate s of fair value cannot be made. As such, ARO liabilities are not recorded for retirement activitie s associated with substations, photovoltaic facilities, and certain hydroelectric facilities; removal of lead-based paint in some facilities and certain communications equipment from leased property; and restoration o f land to specified conditions under ce rtain agreements.

*Nuclear Decommissioning Obligation*

Detailed studies of the cost to decommission the Utility's nuclear generation facilities are conducted every three years in conjunction with the NDCT P. On May 25, 2017, the CPUC issued a final decision in the 2015 NDCTP adopting a nuclear decommissioning cost estimate of $1.1 billion for Humboldt Bay, corresponding to the Utility's request, and $2.4 billion for Diablo Canyon, representing 64% of the U tility's request of $3.8 billion. On an aggregate basis, the final decision adopted a $3.5 billion total nuclear decommissioning cost estimate, compared to $4.8 billion requested by the Utility. Compared to the Utility's estimated cost to decommission Di ablo Canyon, the final decision adopts assumptions which lower costs for large component removal, site security, decommissioning contractor staff, spent nuclear fuel storage, and waste disposal. The Utility can seek recovery of these costs in the 2018 NDC TP. The CPUC's final decision resulted in a $66 mill ion reduction to the ARO on the Consolidated Balance Sheets related to the assumed length of the wet cooling period of spent nuclear fuel after plant shut down.

PG&E Corporation and the Utility recorded an increase of $92 million to the ARO recognized on the Consolidated Balance Sheets, to align the decommissioning cost estimate with the CPUC's final decision on the Utility's application to retire Diablo Canyon Unit 1 by 2024 and Unit 2 by 2025.

The es timated nuclear decommissioning cost is discounted for GAAP purposes and recognized as an ARO on the Consolidated Balance Sheets. The total nuclear decommissioning obligation accrued was $ 3.5 billion at both December 31, 2017 and 2016 . The estimated undiscounted nuclear decommissioning cost for the Utility's nuclear power plants was $ 4.1 billion at December 31, 2017 (or $ 7 billion in future dollars). These estimates are based on the 2017 decommissioning cost studies, prepared in accordance with CPUC requirements.

**Disallowance of Plant Costs**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred or projected to be incurred for recently completed plant will not be recoverable through rates charged to customers and the amount of disallowance can be reasonably estimated. (See "Enforcement and Litigation Matters" in Note 13 below.)

**Nuclear Decommissio ning Trusts**

The Utility's nuclear generation facilities consist of two units at Diablo Canyon and one retired facility at Humboldt Bay. Nuclear decommissioning requires the safe removal of a nuclear generation facilit y from service and the reduction of r esidual radioactivity to a level that permits termination of the NRC license and release of the property for unrestricted use. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized f or release by the CPUC .

The Utility classifies its investments held in the nuclear decommissioning trust s as "available-for-sale." Since the Utility's nuclear decommissioning trust assets are managed by external inve stment managers, the Utility does not have the ability to sell its investments at its discretion. Therefore, all unrealized losses are considered other-than-temporary impairments. Gains or losses on the nuclear decommissioning trust investments are refun dable or recoverable, respectively, from customers through rates. Therefore, trust earnings are deferred and included in the regulatory liability for recoveries in excess of the ARO. There is no impact on the Utility's earnings or accumulated other compr ehensive income. The cost of debt and equity securities sold by the trust is determined by specific identification.

**Variable Interest Entities**

A VIE is an entity that does not have sufficient equity at risk to finance its activities without additional s ubordinated 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 consolid ate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIE s at December 31, 2017, it assessed whether it absorbs any of the VIE's expected losses or receives any portion of the VIE's expected residual returns under the terms of the power purchase agreement , analyzed the variability in the VIE's gross margin , and considered whether it had any decision-making rights associated with the activities that are most significant to the VIE's performance, such as dispatch rights and operating and maintenance activities. T he Utilit y'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 a ny of these VIEs . Since the Utility was not the primary beneficiary of any of these VIEs at December 31, 2017 , it did not consolidate any of them .

**Other Accounting Policies**

For other accounting policies impacting PG&E Corporation's and the Utility's consolidated financial statements, see "Income Taxes" in Note 8, "Derivatives " in Note 9, "Fair Value Measurements" in Note 10 , and "Contingencies an d Commitments" in Note 13 herein.

**Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income**

The changes, net of income tax, in PG&E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2017 consisted of the following:

| **(in millions, net of income tax)** | **Pension Benefits** | **Other Benefits** | **Total** |
|---|---|---|---|
| Beginning balance | **$ (25)** | **$ 16** | **$ (9)** |
| **Other comprehensive income before reclassifications:** | | | |
| Unrecognized prior service cost (net of taxes of $4 and $0, respectively) | (6) | - | (6) |
| Unrecognized net actuarial loss (net of taxes of $229 and $97, respectively) | 333 | 141 | 474 |
| Regulatory account transfer (net of taxes of $225 and $97, respectively) | (327) | (141) | (468) |
| **Amounts reclassified from other comprehensive income:** | | | |
| Amortization of prior service cost (net of taxes of $3 and $6, respectively) [1] | (4) | 9 | 5 |
| Amortization of net actuarial loss (net of taxes of $9 and $2, respectively) [1] | 13 | 2 | 15 |
| Regulatory account transfer (net of taxes of $6 and $8, respectively) [1] | (9) | (10) | (19) |
| **Net current period other comprehensive loss** | **-** | **1** | **1** |
| Ending balance | **$ (25)** | **$ 17** | **$ (8)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

The changes, net of income tax, in PG& E Corporation's accumulated other comprehensive income (loss) for the year ended December 31, 2016 consisted of the following:

| (in millions, net of income tax) | Pension Benefits | Other Benefits | Total |
|---|---|---|---|
| Beginning balance | $ (23) | $ 16 | $ (7) |
| **Other comprehensive income before reclassifications:** | | | |
| Unrecognized prior service cost (net of taxes of $37 and $15, respectively) | 54 | (21) | 33 |
| Unrecognized net actuarial loss (net of taxes of $45 and $15, respectively) | (64) | 21 | (43) |
| Regulatory account transfer (net of taxes of $5 and $0, respectively) | 7 | - | 7 |
| **Amounts reclassified from other comprehensive income:** | | | |
| Amortization of prior service cost (net of taxes of $3 and $6, respectively) [1] | 5 | 9 | 14 |
| Amortization of net actuarial loss (net of taxes of $10 and $2, respectively) [1] | 14 | 2 | 16 |
| Regulatory account transfer (net of taxes of $13 and $8, respectively) [1] | (18) | (11) | (29) |
| **Net current period other comprehensive loss** | **(2)** | **-** | **(2)** |
| **Ending balance** | **$ (25)** | **$ 16** | **$ (9)** |

[1] These components are included in the computation of net periodic pension and other postretirement benefit costs. (See Note 11 below for additional details.)

With the exception of other investments, there was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Accounting Standards Issued But Not Yet Adopted***

***Presentation of Net Periodic Pension Cost***

In March 2017, the FASB issued ASU 2017-07, *Compensation – Retirement Benefits (Topic 715)* , which amends the existing guidance relating to the presentation of net periodic pension cost and net periodic other pos t-retirement benefit costs . 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. In add ition, on a prospective basis, the ASU limits the component of net benefit cost eligible to be capitalized to service costs. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018 . 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 c omponent determined by a plan's actuaries. The change in capitalization of retirement benefits will not have a material impact on PG&E Corporation's and the Utility's Consolidated Financial Statements .

***Recognition of Lease Assets and Liabilities***

In February 2016, the FASB issued ASU No. 2016-02, *Leases (Topic 842)* , which amends the existing guidance relating to the definition of a lease, recognition of lease assets and lease liabilities on the balance sheet, and the disclosure of key information a bout 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 recogni ze 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 q uarter of 2019. PG&E Corporation and the Utility expect this standard to increase lease assets and lease liabilities on the Consolidated Balance Sheets and do not expect the guidance will have a materi al impact on the Consolidated Statements of Income, Statements of Cash Flows and lease disclosures.

***Recognition and Measurement of Financial Assets and Financial Liabilities***

In January 2016, the FASB issued ASU No. 2016-01, *Financial Instruments – Overa ll (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities* , which amends the existing guidance relating to the recognition, measurement, presentation, and disclosure of financial instruments. The amendments require equ ity 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 investmen ts are held in the nuclear decommissioning trusts. These investments are classified as "available-for-sale" and gains or losses are refundable, or recoverable, from customers through rates. The ASU became effective for PG&E Corporation and t he Utility on January 1, 2018 and will not have a material impact on the Consolidated Financial Statements and related disclosur es .

***Revenue Recognition Standard***

In May 2014, the FASB issued ASU No. 2014-09, *Revenue from Contracts with Customers (Topic 606)* , which amends existing 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 capit al markets and to provide more useful information to users of financial statements through improved and expanded disclosure requirements. The ASU became effective for PG&E Corporation and the Utility on January 1, 2018. This standard will be adopted for related disclosures in the first quarter of 2018 and will not have a material impact on the Consolidated Financial Statements. Upon adoption of ASU 2014-09, the Utility plans to disclose revenues from contracts with customers separately from regulatory ba lancing account revenue and disaggregate customer contract revenue by customer class.

## NOTE 3: REGULATORY ASSETS, LIABILITIES, AND BALANCING ACCOUNTS

### Regulatory Assets

*Current Regulatory Assets*

At December 31, 2017 and 2016, the Utility had current regulatory assets of $615 million and $423 million, respectively. At December 31, 2017 and 2016, the current regulatory assets included $426 million and $223 million, respectively, of costs related to CEMA fire preve ntion and vegetation management. Curre nt regulatory assets are included within the current assets in the Consolidated Balance Sheets.

*Long-Term Regulatory Assets*

Long-term regulatory assets are comprised of the following:

| (in millions) | Balance at December 31, 2017 | 2016 | Recovery Period |
|---|---|---|---|
| Pension benefits [1] | $ 1,954 | $ 2,429 | Indefinitely [3] |
| Deferred income taxes [1][4] | - | 3,859 | |
| Utility retained generation [2] | 319 | 364 | 9 years |
| Environmental compliance costs [1] | 837 | 778 | 32 years |
| Price risk management [1] | 65 | 92 | 10 years |
| Unamortized loss, net of gain, on reacquired debt [1] | 79 | 76 | 25 years |
| Other | 539 | 353 | Various |
| **Total long-term regulatory assets** | **$ 3,793** | **$ 7,951** | |

(1) Represents the cumulative differences between amounts recognized for ratemaking purposes and expense or accumulated other comprehensive income (loss) recog nized in accordance with GAAP.

(2) In connection with the settlement agreement entered into among PG &E Corporation, the Utility, and the CPUC in 2003 to resolve the Utility's proceeding under Chapter 11, the CPUC authorized the Utility to recover $ 1.2 billion of costs related to the Utility's retained generation assets. The individual components of thes e regulatory assets are being amortized over the respective lives of the underlying generation facilities, consistent with the period over which the related revenues are recognized.

(3) Payments into the pension and other benefits plans are based on annu al contribution requirements. As these annual requirements continue indefinitely into the future, t he Utility expects to continuously recover pension benefits.

(4) The change in the balance from a regulatory asset as of December 31, 2016 to a regulatory li ability as of December 31, 2017 reflects the impact of changes in net deferred tax liabilities associated with a lower federal income tax rate as a result of the Tax Act. (See "Regulatory Liabilities" below and Note 8.)

At December 31, 2017 and 2016, other long-term regulatory assets included $274 million and $70 million, respectively, of costs related to CEMA events from 2014 through 2017 that the Utility believes are recoverable based on historical experience in recover ing costs for these types of events.

In general, the Utility does not earn a return on regulatory assets if the related costs do not accrue interest. Accordingly, the Utility earns a return only on its regulatory assets for retained generation , and unam ortized loss, net of gain, on reacquired debt.

**Regulatory Liabilities**

*Long-Term Regulatory Liabilities*

Long-term regulatory liabilities are comprised of the following:

| (in millions) | Balance at December 31, 2017 | 2016 |
|---|---|---|
| Cost of removal obligations [1] | $ 5,547 | $ 5,060 |
| Deferred income taxes [2] | 1,021 | - |
| Recoveries in excess of AROs [3] | 624 | 626 |
| Public purpose programs [4] | 590 | 567 |
| Other | 897 | 552 |
| **Total long-term regulatory liabilities** | **$ 8,679** | **$ 6,805** |

(1) Represents the cumulative differences between asset removal costs recorded and amounts collected in rates for expected asset removal costs.

(2) Represents the net of amounts owed to customers for deferred taxes collected at higher rates before the Tax Act and amounts owed to the Utility for reversal of deferred taxes subject to flow-through treatment . (See Note 8 below.)

(3) Represents the cumulative differences between ARO expenses and amounts collected in rates. Decommissioning costs related to the Utility's nuclear facilities are recovered through rates and are placed in nuclear decommissioning trusts. This regulatory liability also represents the deferral of realized and unrealized gains and losses o n the se nuclear decommissioning trust investments. (See Note 10 below.)

(4) Represents amounts received from customers designated for public purpose program costs expected to be incurred beyond the next 12 months, primarily rela ted to energy efficiency programs.

**Regulatory Balancing Accounts**

The Utility tracks (1) differences between the Utility's authorized revenue requirement and customer billings, and (2) differences between incurred costs and customer billings. To the extent these differences are probable of recovery or refund over the next 12 months, the Utility records a current regulatory balancing account receivable or payable. Regulatory balancing accounts that the Utility expects to collect or refund over a perio d exceeding 12 months are recorded as other noncurrent assets – regulatory assets or noncurrent liabilities – regulatory liabilities, respectively, in the Consolidated Balance Sheets. These differences do not have an impact on net income . Balancing accou nts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and cu stomer revenues are collected.

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

| | Receivable Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2017** | **2016** |
| Electric distribution | $ - | $ 132 |
| Electric transmission | 139 | 244 |
| Utility generation | - | 48 |
| Gas distribution and transmission | 486 | 541 |
| Energy procurement | 71 | 132 |
| Public purpose programs | 103 | 106 |
| Other | 423 | 297 |
| **Total regulatory balancing accounts receivable** | **$ 1,222** | **$ 1,500** |

| | Payable Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2017** | **2016** |
| Electric distribution | $ 72 | $ - |
| Electric transmission | 120 | 99 |
| Utility generation | 14 | - |
| Gas distribution and transmission | - | 48 |
| Energy procurement | 149 | 13 |
| Public purpose programs | 452 | 264 |
| Other | 313 | 221 |
| **Total regulatory balancing accounts payable** | **$ 1,120** | **$ 645** |

The electric distribution and utility generation accounts track the collection of revenue requirements approved in the GRC. The electric transmission accounts track recovery of costs related to the transmission of electricity. The gas distribution and transmission accounts track the collection of revenue requirements approved in the GRC and the GT&S rate case. Energy procurement balancing accounts track recovery of costs related to the procurement of electricity, including any environmental compliance-related activities. P ublic purpose programs balancin g accounts are primarily used to record and recover authorized revenue requirements for commission-mandated pro grams such as energy efficiency.

**NOTE 4: DEBT**

**Long-Term Debt**

The following table summarizes PG&E Corporation's and the Utility's long-term de bt:

| (in millions) | | December 31, 2017 | December 31, 2016 |
|---|---|---|---|
| **PG&E Corporation** | | | |
| Senior notes: | | | |
| Maturity | Interest Rates | | |
| 2019 | 2.40% | $ 350 | $ 350 |
| Unamortized discount, net of premium and debt issuance costs | | - | (2) |
| **Total PG&E Corporation long-term debt** | | **350** | **348** |
| **Utility** | | | |
| Senior notes: | | | |
| Maturity | Interest Rates | | |
| 2017 | 5.63% | - | 700 |
| 2018 | 8.25% | 400 | 800 |
| 2020 | 3.50% | 800 | 800 |
| 2021 | 3.25% to 4.25% | 550 | 550 |
| 2022 | 2.45% | 400 | 400 |
| 2023 through 2047 | 2.95% to 6.35% | 14,975 | 12,375 |
| Less: current portion [1] | | (400) | (700) |
| Unamortized discount, net of premium and debt issuance costs | | (185) | (161) |
| **Total senior notes, net of current portion** | | **16,540** | **14,764** |
| Pollution control bonds: | | | |
| Maturity | Interest Rates | | |
| Series 2004 A-D due 2023 [2] | 4.75% | - | 345 |
| Series 2008 F and 2010 E, due 2026 [3] | 1.75% | 100 | - |
| Series 2008 G, due 2018 [4] | 1.05% | 45 | - |
| Series 2009 A-B, due 2026 [5] | 1.78% | 149 | 149 |
| Series 1996 C, E, F, 1997 B due 2026 [6] | variable rate [7] | 614 | 614 |
| Less: current portion | | (45) | - |
| **Total pollution control bonds** | | **863** | **1,108** |
| **Total Utility long-term debt, net of current portion** | | **17,403** | **15,872** |
| **Total consolidated long-term debt, net of current portion** | | **$ 17,753** | **$ 16,220** |

[1] On January 19, 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 February 18, 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.

[2] In June 2017, the Utility repurchased and retired $345 million principal amount o f Pollution Control Bonds series 2004 A-D.

[3] Pollution Control Bonds series 2008F and 2010E were remarketed and issued in June 2017. Although the stated maturity date for both series is 2026, these bonds have a mandatory redemption date of May 30, 2022.

[4] Pollution Control Bonds series 2008G were remarketed and issued in June 2017 and mature on December 1, 2018.

[5] Each series of these bonds is supported by a separate direct-pay letter of credit . Subject to certain requirements, the Utility may choose not to provide a credit facility without issuer consent.

[6] Each series of these bonds is supported by a separate letter of credit . In December 2015, the letters of credit were extended to Decem ber 1, 20 20 . Although the stated maturity date is 2026, each series will remain outstanding only if the Utility extends or replaces the letter of credit related to the series or otherwise obtains consent from the issuer to the continuation of the series w ithout a credit facility.

[7] At December 31, 2017, the interest rate on these bonds ranged from 1.45% - 1.70%.

***Pollution Control Bonds***

The California Pollution Control Financing Authority and the California Infrastructure and Economic Development Bank have issued various series of fixed rate and multi-modal tax-exempt pollution control bonds for the benefit of the Utility. Substantially all of the net proceeds of the pollution control bonds were used to finance or refinance pollution control and sewage and solid waste disposal facilities at the Geysers geothermal power plant or at the Utility's Diablo Canyon nuclear power plant . In 1999, the Utility sold all bond-financed facilities at the non-retired units of the Geysers geothermal power plant to Geys ers Power Company, LLC pursuant to purchase and sale s agreements stating that Geysers Power Company, LLC will use the bond-financed facilities solely as pollution control facilities for so long as any tax-exempt pollution control bonds issued to finance th e Geysers project are outstanding . Except for components that may have been abandoned in place or disposed of as scrap or that are permanently non-operational, t he Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-fi nanced facilities solely as pollution control facilities.

**Repayment Schedule**

PG&E Corporation's and the Utility's combined long-term debt principal repayment amounts at December 31, 2017 are reflected in the table below:

| (in millions, except interest rates) | 2018 | 2019 | 2020 | 2021 | 2022 | Thereafter | Total |
|---|---|---|---|---|---|---|---|
| **PG&E Corporation** | | | | | | | |
| Average fixed interest ra te | - | 2.40% | - | - | - | - | 2.40% |
| Fixed rate obligations | $ - | $ 350 | $ - | $ - | $ - | $ - | $ 350 |
| **Utility** | | | | | | | |
| Average fixed interest rate | 7.52% | - | 3.50% | 3.80% | 2.31% | 4.68% | 4.61% |
| Fixed rate obligations | $ 445 | $ - | $ 800 | $ 550 | $ 500 [2] | $ 14,975 | $ 17,270 |
| Variable interest rate as of December 31, 2017 | - | 1.78% | 1.59% | - | - | - | 1.63% |
| Variable rate obligations [1] | $ - | $ 149 | $ 614 | $ - | $ - | $ - | $ 763 |
| **Total consolidated debt** | **$ 445** | **$ 499** | **$ 1,414** | **$ 550** | **$ 500** | **$ 14,975** | **$ 18,383** |

[1] The bonds due in 2026 are backed by separate letters of credit that expire June 5, 2019, or December 1, 2020.
[2] Pollution Control Bonds series 2008F and 2010E were remarketed and issued in June 2017. Altho ugh the stated maturity date for both series is 2026, these bonds have a mandatory redemption date of May 30, 2022.

**Short-term Borrowings**

The following table summarizes PG&E Corporation's and the Utility's outstanding borrowings under their revolving cre dit facilities and commercial paper program s at December 31, 2017 :

| (in millions) | Termination Date | Credit Facility Limit | Letters of Credit Outstanding | Commercial Paper Outstanding | Facility Availability |
|---|---|---|---|---|---|
| PG&E Corporation | April 2022 | $ 300 [1] | $ - | $ 132 | $ 168 |
| Utility | April 2022 | 3,000 [2] | 49 | 50 | 2,901 |
| **Total revolving credit facilities** | | **$ 3,300** | **$ 49** | **$ 182** | **$ 3,069** |

[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 $ 50 0 m illion lender commitment to the letter of credit sublimit and a $ 75 million commitment for swingline loans.

For the year ended December 31, 2017 , PG&E Corporation's average outstanding commercial paper balance was $ 81 million and the maximum out standing balance during the year was $ 161 million. For 2017 , the Utility's average outstanding commercial paper balance was $ 469 million and the maximum outstanding balance during the year was $ 1.1 billion . There were no bank borrowings for PG&E Corporation or t he U tility in 2017 .

***Revolving Credit Facilities***

In May 2017, PG&E Corporation and the Utility each extended the t ermination dates of their existing revolving credit facilities by one year from April 27, 2021 to April 27, 2022. PG&E Corporation's and the Utility's revolving credit facilities may be used for working capital, the repayment of commercial paper, and othe r corporate purposes.

Borrowings under each credit agreement (other than swingline loans) will bear interest based on the borrower’s credit rating and on each borrower’s election of either (1) a London Interbank Offered Rate (“LIBOR”) plus an applicable margin or (2) the base rate plus an applicable margin. The base rate will equal the higher of the following: the administrative agent’s announced base rate, 0.5% above the overnight federal funds rate, and the one-month LIBOR plus an applicable margin. T he borrower’s credit rating at the time of borrowing will determine the applicable rate within the following ranges. The applicable margin for LIBOR loans will range between 0.9% and 1.475% under PG&E Corporation’s credit agreement and between 0.8% and 1. 275% under the Utility’s credit agreement. The applicable margin for base rate loans will range between 0% and 0.475% under PG&E Corporation’s credit agreement and between 0% and 0.275% under the Utility’s credit agreement. In addition, the facility fee under PG&E Corporation’s and the Utility’s credit agreements will range between 0.1% and 0.275% and between 0.075% and 0.225%, respectively.

PG&E Corporation’s and the Utility’s revolving credit facilities include usual and customary provisions for revol ving credit facilities of this type, including those regarding events of default and covenants limiting liens to those permitted under their senior note indentures, mergers, sales of all or substantially all of their assets, and other fundamental changes. In addition, the respective revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter . PG&E Corporation’s revolving credit facility agreement also requires that PG&E Corporation own s , directly or indirectly, at least 80% of the outstanding common stock and at least 70% of the outstanding voting capital stock of the Utility.

***Commercial Paper Program s***

The borrowings from PG&E Corporation’s and the Utility ’s commercial paper programs are used primarily to fund temporary financing needs. PG&E Corporation and the Utility can issue commercial paper up to the maximum amounts of $300 million and $2.5 billion, re spectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities. The commercial paper may have maturities up to 365 days and ranks equ ally with PG&E Corporation’s and the Utility’s other unsubordinated and unsecured indebtedness. Commercial paper notes are sold at an interest rate dictated by the market at the time of issuance. For 2017 , the average yield on outstanding PG&E Corporatio n and Utility commercial paper was 1.29 % and 1.11 % , respectively .

***Other Short-term Borrowings***

In February 2017, t he Utility’s $250 million floating rate unsecured term loan, issued in March 2016, matured and was repaid. Additionally, in February 2017, the Utility entered into a $250 million floating rate unsecured term loan maturing on February 22, 2018. The procee ds were used for general corporate purposes, including the repayment of a portion of the Utility’s outstanding commercial paper.

In November 2017, the Utility issued $500 million in unsecured floating rate senior notes that mature on November 28, 2018. The proceeds were used towards repayment of the $250 million unsecured floating rate senior notes due November 30, 2017 and the balance was used to support the Northern California wildfire response efforts.

**NOTE 5: COMMON STOCK AND SHARE-BASED COMPENSATIO N**

PG&E Corporation had 514,755,845 shares of common stock outstanding at December 31, 2017 . PG&E Corporation held all of the Utility’s outstanding common stock at December 31, 201 7.

In February 2017, PG&E Corporation amended its February 2015 EDA providing for the sale of PG&E Corporation common stock having an aggregate price of up to $275 million. During 2017 , PG&E Corporation sold 0.4 million shares of its common stock under the February 2017 EDA for cash proceeds of $ 28.4 million, net of commissions paid of $ 0.2 million . There were no issuances under the February 2017 EDA for the three months ended December 31, 2017. As of December 31, 2017, the remaining sales available under this agreement were $ 246.3 million.

In addition, during 2017, PG&E Corporation sold 7.4 million shares of common stock under its 401(k) plan, the Dividend Reinvestment and Stock Purchase Plan, and share-based compensation plans for total cash proceeds of $ 366.4 million .

**Dividends**

Ordinarily, the Board of Directors of PG&E Corporation and the Utility declare dividends quarterly. Under the Utility's Articles of Incorporation, the Utility cannot pay common stock dividends unless all cumulative preferred dividends on the Utility's preferred stock have been paid. Under their r espective credit agreements, PG&E Corporation and the Utility are each required to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%. Based on the calculation of this ratio for each company, no amount of PG&E Corpo ration's retained earnings and $218 million of the Utility's retained earnings was subject to this restriction at December 31, 2017. Additionally, the Utility's net assets, and therefore its ability to pay dividends, are restricted by the CPUC-authorized capital structure, which requires the Utility to maintain, on average, at least 52% equity. Based on the calculation of this ratio, $14.3 billion of the Utility's net assets were restricted at December 31, 2017. Additionally, as a result of this requirement, the Utility's ability to pay dividends in the future could be impacted by future potential liabilities. On December 20, 2017, the Board of Directors of PG&E Corporation suspended quarter ly cash dividends on PG&E Corporation's common stock, beginning with the fourth quarter of 2017 due to uncertainty related to the causes of and potential liabilities associated with the Northern California wildfires. (See "Northern California Wildfires" i n Note 13 below.)

For the first quarter of 2017, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.49 per share quarterly. In May 2017, the Board of Directors of PG&E Corporation approved a new annual common stock cash dividend of $0.53 per share quarterly. In 2017, total dividends declared were $1.55 per share.

**Long-Term Incentive Plan**

The PG&E Corporation LTIP permits various forms of share-based incentive awards, including restricted stock awards, restricted stock units , performance shares, and other share-based awards, to eligible employees of PG&E Corporation and its subsidiaries. Non-employee directors of PG&E Corporation are also eligible to receive certain share-based awards. A maximum of 1 7 million shares o f PG&E Corporation common stock (subject to certain adjustment s ) has been reserved for issuance under the 20 14 LTIP, of which 14,327,157 shares were available for future award s at December 31, 2017 .

The following table provides a summary of total share-based compensation expense recognized by PG&E Corporation for share-based incentive awards for 2017 , 2016 , and 2015 :

| **(in millions)** | **2017** | | **2016** | | **2015** | |
|---|---|---|---|---|---|---|
| Restricted stock units | $ | 40 | $ | 53 | $ | 47 |
| Performance shares | | 45 | | 55 | | 46 |
| Total compensation expense (pre-tax) | **$** | **85** | **$** | **108** | **$** | **93** |
| Total compensation expense (after-tax) | **$** | **50** | **$** | **64** | **$** | **55** |

The amount of s hare-based compensation costs capitalized during 2017 , 2016 , and 2015 was immaterial . There was no material difference between PG&E Corporation and the Utility for the information disclosed above.

***Restricted Stock Units***

R estricted stock units generally vest equally over three year s . Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any divi dend equivalents associated with the vested restricted stock units. Compensation expense is generally recognized rateably over the vesting period based on grant-date fair value . The weighted average grant-date fair value for restricted stock units grante d during 2017 , 2016 , and 2015 was $ 66.95 , $ 56.68 , and $ 53.30 , respectively. The total fair value of restricted stock units that vested during 2017 , 2016 , and 2015 was $ 57 million, $ 36 million, and $ 57 million, respectively. The tax benefit from restricted stock units that vested during each period was not material. In general, f orfeitures are recorded rateably over the vesting period, using historical averages and adjusted to act uals when vesting occurs. As of December 31, 2017 , $ 33 mil lion of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remai ning weighted average period of 1.46 years.

The following table summarizes restricted stock unit activity for 2017 :

| | Number of Restricted Stock Units | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at January 1 | 1,923,010 | $ 51.26 |
| Granted | 658,395 | 66.95 |
| Vested | (1,172,194) | 48.44 |
| Forfeited | (29,976) | 61.07 |
| Nonvested at December 31 | **1,379,235** | $ 60.93 |

***Performance Shares***

Performance shares generally will vest three years after the grant date. Upon vesting, performance shares are settled in shares of common stock based on either PG&E Corporation's total shareholder return relative to a specified group of industry peer companies over a three-year performance period or , for a small number of awards, an internal PG&E Corpor ation metric . Dividend equivalents are paid in cash based on the amount of common stock to which the recipients are entitled.

Compensation expense attributable to performance share is generally recognized rateably over the applicable three-year period based on the grant-date fair value determined using a Monte Carlo simulation valuation model for the total shareholder return based awards or the grant-date market value o f PG&E Corporation common stock for internal metric based awards. The weighted average grant-date fair value for performance shares granted during 2017 , 2016 , and 2015 was $ 77.00 , $ 53.61 , and $ 68.27, respective ly. The re was no tax benefit associated with performance shares during each of these periods . In general, f orfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2017 , $ 46 million of total unrecognized compensation costs related to nonvested performance shares was expected to be recognized over the remaining weighted average period of 1.42 ye ar s .

The following table summarizes activity for performance shares in 2017 :

| | Number of Performance Shares | Weighted Average Grant-Date Fair Value |
|---|---|---|
| Nonvested at January 1 | 1,838,855 | $ 58.65 |
| Granted | 745,724 | 77.00 |
| Vested | (81,501) | 53.74 |
| Forfeited [1] | (755,050) | 66.30 |
| Nonvested at December 31 | **1,748,028** | $ 63.40 |

[1] Includes performance shares that expired with zero value as performance targets were not met.

**NOTE 6: PREFERRED STOCK**

PG&E Corporation has authorized 80 million shares of no par value preferred stock and 5 million shares of $ 100 par value preferred stock , which may be issued as redeemable or nonredeemable preferred stock. PG&E Corporation does not have any preferred stock outstanding .

The Utility has authorized 75 million shares of $ 25 par value preferred stock and 10 million shares of $ 100 par value preferred stock. At December 31, 2017 and December 31, 2016, the Utility's preferred stock outstanding included $ 145 million o f shares with interest rates between 5% and 6% designated as nonredeemable preferred stock and $ 113 million of shares with interest rates between 4.36% and 5% that are redeemable between $ 25.75 and $ 27.25 per share. The Utility's preferred stock outstanding are not subject to mandatory redemption. All outstanding preferred stock has a $25 par value.

At December 31, 2017 , annual dividends on the Utility's nonredeemable pre ferred stock ranged from $ 1.25 to $ 1.50 per share. The Utility's redeemable preferred stock is subject to redemption at the Utility's option, in whole or in part, if the Utility pays the specified redemption price plus accumulated and unpaid dividends through the redemption date. At December 31, 2017 , annual d ividends on redeemable preferred stock ranged from $ 1.09 to $ 1.25 per share.

On December 20, 2017, the Boards of Directors of P G&E Corporation and the Utility determined to suspend quarterly cash dividends on the Utility's preferred stock, beginning with the three-month period ending January 31, 2018, due to uncertainty related to causes and potential liabilities associated with the October 2017 Northern California wildfir es. See "Northern California Wildfires" in Note 13 below .)

Dividends on all Utility preferred stock are cumulative. All shares of preferred stock have voting rights and an equal preference in dividend and liquidation rights. Upon liquidation or dissolution of the Utility, holders of preferred stock would be entitled to the par value of such shares plus all accumulated and unpaid dividends, as specified for the class and series. T he Utility paid $ 14 million of dividends on preferred stock in each of 2017, 2016, and 2015.

**NOTE 7: 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 a nd weighted average common shares outstanding for calculating diluted EPS for 2017 , 2016 , and 2015 .

| | Year Ended December 31, | | |
|---|---|---|---|
| **(in m illions, except per share amounts)** | **2017** | **2016** | **2015** |
| **Income available for common shareholders** | $ 1,646 | $ 1,393 | $ 874 |
| **Weighted average common shares outstanding, basic** | 512 | 499 | 484 |
| Add incremental shares from assumed conversions: | | | |
| Employee share-based compensation | 1 | 2 | 3 |
| **Weighted average common share outstanding, diluted** | 513 | 501 | 487 |
| **Tot al earnings per common share, diluted** | **$ 3.21** | **$ 2.78** | **$ 1.79** |

For each of the periods presented above, the calculation of outstanding common shares on a diluted basis excluded an insignificant amount of options and securities that were antidilutive.

**NOTE 8: INCOME TAXES**

PG&E Corporation and the Utility use the asset and liability method of accounting for income taxes. The i ncome tax provision includes current and deferred income taxes resulting from operations during the year. PG&E Corporation and the Utility estimate current period tax expense in addition to calculating deferred tax assets and liabilities. Deferred tax assets and liabilities result from temporary tax and accounting timing differences, such as those arising from depreciation expens e.

PG&E Corporation and the Utility recognize a tax benefit if it is more likely than not that a tax position taken or expected to be taken in a tax return will be sustained upon examination by taxing authorities based on the merits of the position. T he tax benefit recognized in the financial statements is measured based on the largest amount of benefit that is greater than 50% likely of being realized upon settlement. As such, t he difference between a tax position taken or expected to be taken in a t ax return in future periods and the benefit recognized and measured pursuant to this guidance in the financial statements represents an unrecognized tax benefit.

Investment tax credits are deferred and amortized to income over time. PG&E Corporation am ortizes its investment tax credits over the projected investment recovery period. The Utility amortizes its investment tax credits over the life of the related property in accordance with regulatory treatment.

PG&E Corporation files a consolidated U.S. f ederal income tax return that includes the Utility and domestic subsidiaries in which its ownership is 80% or more. PG&E Corporation files a combined state income tax return in California. PG&E Corporation and the Utility are parties to a tax-sharing agr eement under which the Utility determines its income tax provision (benefit) on a stand-alone basis.

The significant components of income tax provision (benefit) by taxing jurisdiction were as follows :

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| **(in millions)** | **2017** | **2016** | **2015** | **2017** | **2016** | **2015** |
| Current: | | | | | | |
| Federal | $ (10) | $ (105) | $ (89) | $ 61 | $ (105) | $ (88) |
| State | 48 | (70) | 11 | 50 | (66) | 6 |
| Deferre d: | | | | | | |
| Federal | 481 | 218 | 131 | 326 | 229 | 136 |
| State | 6 | 16 | (76) | 4 | 16 | (69) |
| Tax credits | (14) | (4) | (4) | (14) | (4) | (4) |
| **Income tax provision (benefit)** | **$ 511** | **$ 55** | **$ (27)** | **$ 427** | **$ 70** | **$ (19)** |

The following table describes net deferred income tax liabilities:

| | PG&E Corporation | | Utility | |
|---|---|---|---|---|
| | Year Ended December 31, | | | |
| **(in millions)** | **2017** | **2016** | **2017** | **2016** |
| **Deferred income tax assets:** | | | | |
| Tax carryforwards | $ 830 | $ 1,851 | $ 736 | $ 1,596 |
| Compensation | 274 | 277 | 205 | 199 |
| Income tax regulatory liability [(1)] | 286 | - | 286 | - |
| Other [(2)] | 185 | 186 | 194 | 203 |
| **Total deferred income tax assets** | **$ 1,575** | **$ 2,314** | **$ 1,421** | **$ 1,998** |
| **D eferred income tax liabilities:** | | | | |
| Property related basis differences | 7,269 | 10,429 | 7,256 | 10,411 |
| Income tax regulatory asset [(1)] | - | 1,572 | - | 1,572 |
| Other [(3)] | 128 | 526 | 128 | 525 |
| **Total deferred income tax liabilities** | **$ 7,397** | **$ 12,527** | **$ 7,384** | **$ 12,508** |
| **Total net deferred income tax liabilities** | **$ 5,822** | **$ 10,213** | **$ 5,963** | **$ 10,510** |

(1) Represents the tax gross up portion of the deferred income tax for the cumulative differences between amounts recognized for ratemaking purposes and amounts recognized for tax, including the impact of changes in net deferred taxes associated with a lower federal income tax rate as a result of the Tax Act. (For more information see Note 3 above and "Tax Cuts and Jobs Act of 2017" below.)

(2) Amounts include benefits, environmental reserve, and customer advances fo r construction.

(3) Amounts primarily relate to regulatory balancing accounts.

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

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | | | |
| | **2017** | **2016** | **2015** | **2017** | **2016** | **2015** |
| Federal statutory income tax rate | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % | 35.0 % |
| Increase (decrease) in income tax rate resulting from: | | | | | | |
| State income tax (net of federal benefit) [(1)] | 1.5 | (2.5) | (4.9) | 1.6 | (2.2) | (4.8) |
| Effect of regulatory treatment of fixed asset differences [(2)] | (16.5) | (23.7) | (33.6) | (16.8) | (23.4) | (33.7) |
| Tax credits | (1.1) | (0.8) | (1.3) | (1.1) | (0.8) | (1.3) |
| Benefit of loss carryback | - | (1.1) | (1.5) | - | (1.1) | (1.5) |
| Non deductible penalties [(3)] | 0.4 | 0.8 | 4.3 | 0.4 | 0.8 | 4.3 |
| Tax Reform Adjustment [(4)] | 6.8 | - | - | 3.0 | - | - |
| Other, net [(5)] | (2.5) | (3.9) | (1.1) | (2.0) | (3.5) | (0.2) |
| **Effective tax rate** | **23.6 %** | **3.8 %** | **(3.1) %** | **20.1 %** | **4.8 %** | **(2.2) %** |

(1) Includes the effect of state flow -through ratemaking treatment. In 2016 and 2015, amounts reflect an agreement with the IRS on a 2011 audit related to electric transmission and distribution repairs deductions. The 2017 amount reflects an agreement with the IRS on a 2013 audit related to generati on repairs deductions.

(2) I nclude s the effect of federal flow-through ratemaking treatment for certain property-related costs as authorized by the 2014 GRC decision in all periods presented and by the 2015 GT&S decision which impacted 2016 and 2017. All amounts are impacted by the level of income before income taxes. The 2014 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. Therefor e, 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 r ecovered from or returned to customers in future rates.

(3) Primarily represen ts the effect s of a non-tax deductible penalty associated with the Butte fire for 2017, non-tax deductible fines and penalties associated with the natural gas distribution fac ilities record-keeping decision for 2016 and the effects of the San Bruno Penalty Decision for 2015 .
(4) Represents the required adjustment to deferred tax balances, due to the federal income tax rate being lowered from 35% to 21% beginning in 2018 as a result of the enactment of the Tax Act.
(5) These amounts primarily represent the impact of tax audit settlements.

***Unrecognized Tax B enefits***

The following table reconciles the changes in unrecognized tax benefits:

| | PG&E Corporation | | | Utility | | |
|---|---|---|---|---|---|---|
| **(in millions)** | **2017** | **2016** | **2015** | **2017** | **2016** | **2015** |
| **Balance at beginning of year** | $ 388 | $ 468 | $ 713 | $ 382 | $ 462 | $ 707 |
| Additions for tax position taken during a prior year | - | - | 40 | - | - | 40 |
| Reductions for tax position taken d uring a prior year | (71) | (77) | (349) | (71) | (77) | (349) |
| Additio ns for tax position taken during the current year | 48 | 56 | 64 | 48 | 56 | 64 |
| Settlements | (14) | (59) | - | (8) | (59) | - |
| Expirat ion of statute | (3) | - | - | (3) | - | - |
| **Balance at end of year** | **$ 349** | **$ 388** | **$ 468** | **$ 349** | **$ 382** | **$ 462** |

The component of unre cognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2017 for PG &E Corporation and the Utility was $ 21 million .

PG&E Corporation's and the Utility's unrecognized tax benefits may change significantly within the next 12 months due to the resolution of several matters, including audits. As of December 31, 2017, it is reasonably possible that unrecognized tax benefits will decrease by approximately $ 20 million within the next 12 months.

Interest income, interest expense and penalties associated with income taxes are reflected in income tax expense on the Consolidated Statements of In come. For t he years ended December 31, 2017 , 2016, and 201 5 , these amounts were immaterial.

***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 provi sions, the Tax Act reduces the federal income tax rate from 35 percent to 21 percent 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 in come tax assets and liabilities to reflect the reduction in the federal tax rate. PG&E Corporation and the Utility have made reasonable estimates to reflect the impacts of the Tax Act and recorded provisional amounts, in accordance with rules issued by th e SEC in Staff Account ing Bulletin No. 118 , for the re-measurement of deferred tax balances as of December 31, 2017.

During the three months and year ended December 31, 2017, PG&E Corporation, on a consolidated basis, recorded a one-time provisional tax expense of $147 million to reflect the transitional impacts of the Tax Act. Of this amount, $83 million is attributable to the re-measurement of PG&E Corporation's net deferred tax asset comprised primarily of net operating loss carry-forwards and compen sation-related items. The remaining $64 million is related to the re-measurement of the Utility's deferred taxes not reflected in authorized revenue requirements, such as disallowed plant. The Utility also recorded a provisional $5. 7 billi on re-measurement of its deferred tax balances (related to flow-through and normalized timing differences for plant-related items) which was offset by a change from a net deferred income tax regulatory asset to a net regulatory liability. The deferred inc ome tax regulatory liability will be refunded to customers over the regulatory lives of the related assets.

The final transition impacts of the Tax Act may differ from the above recorded amounts, possibly materially, due to, among other things, regulato ry decisions from the CPUC that could differ from the Utility's determination of how the impacts of the Tax Act are allocated between customers and shareholders. In addition, while PG&E Corporation and the Utility were able to make reasonable estimates of the impact of the reduction in federal tax rate and the elimination of bonus depreciation due to the enactment of the Tax Act; changes in interpretations, guidance on legislative intent, and any changes in accounting standards for income taxes in response to the Tax Act could impact the recorded amounts. PG&E Corporation and the Utility will finalize and record any adjustments related to the Tax Act within the one year measurement period provided under S taff Accounting Bulletin No. 118 .

***Tax Settlements***

PG& E Corporation's tax returns have been accepted through 2015 except for a few matters, the most significant of which relates to deductible repair costs for gas transmission and distribution lines of business. In February 2017, the Joint Committee of Taxati on approved PG&E Corporation's settlement with the IRS related to deductible electric transmission and distribution repairs for the 2011 and 2012 tax years. The agreement provided that the methodology used in determining the deductible amount should be fo llowed for all subsequent periods, absent any material change in facts. In November 2017, PG&E Corporation reached an agreement with the IRS on deductible generation repairs for the 2013 and 2014 tax years. The IRS may issue guidance in 2018 that clarifi es which repair costs are deductible for the natural gas transmission and distribution lines of business.

Tax years after 2008 remain subject to examination by the state of California.

***2015 Gas Transmission and Storage Rate Case***

The final phase two de cision reduced rate base by the full amount of the disallowed capital expenditures but did not remove the associated deferred taxes, which the Utility believes constitutes a normalization violation. In the final decision, the CPUC authorized the Utility t o establish a Tax Normalization Memorandum Account to track relevant costs and clarified that it is the CPUC's intention that the Utility comply with normalization rules and avoid the potential adverse consequences of a normalization violation. The CPUC a llowed the Utility to seek a ruling from the IRS and the Utility filed the ruling request with the IRS on April 10, 2017. On October 5, 2017, the IRS issued a private letter ruling indicating the final decision rate base reduction was inconsistent with the IRS tax normalization requiremen ts. As a result of the IRS private letter ruling, the Utility filed an advice letter with the CPUC on December 11, 2017, requesting a rate base adjustment of $7 million, $28 million, $49 million, and $61 million, in 2015, 2016, 2017, and 2018, respectively.

***Carryforwards***

The following table describes PG&E Corporation's operating loss and tax credit carryforward balances :

| (in millions) | December 31, 2017 | Expiration Year |
|---|---|---|
| **Federal:** | | |
| Net operating loss carryforward | $ 4,233 | 2031 - 2036 |
| Tax credit carryforward | 103 | 2029 - 2036 |
| Charitable contribution loss carryforward | 93 | 2019 - 2021 |
| | | |
| **State:** | | |
| Net operating loss carryforward | $ - | N/A |
| Tax credit carryforward | 13 | Various |
| Charitable contribution loss carryforward | 24 | 2020 - 2021 |

PG&E Corporation believes it is more likely than not the tax benefits associated with the federal and California net operating loss es, charitable contributions and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 201 7 for these tax attributes.

**NOTE 9: 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 volatili ty in customer rates due to fluctuating commodity prices. Derivatives include contracts, such as power purchase agreements, forwards, futures, swaps, options, and CRRs .

Derivatives are presented in the Utility's Consolidated Balance Sheets recorded at fa ir 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 Consolidated Balance Sheets. These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Uti lity 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 unreali zed 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 Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives a re 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 d erivatives. 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 Consolidated Balance Sheets at fair value. Eligible derivatives are accounted for under the accrual method of accounting.

**Volume of Derivative Activity**

At December 31, 2017 and 2016 , respectively , the volume s of the Utility's outstanding derivatives w ere as follows:

| | | Contract Volume | |
|---|---|---|---|
| **Underlying Product** | **Instruments** | **2017** | **2016** |
| Natural Gas [(1)] (MMBtus [(2)]) | Forwards and Swaps | 228,768,745 | 323,301,331 |
| | Options | 60,736,806 | 96,602,785 |
| Electricity (Megawatt-hours) | Forwards and Swaps | 2,872,013 | 3,287,397 |
| | Congestion Revenue Rights [(3)] | 312,272,177 | 278,143,281 |

[(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 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** |

At December 31, 2016 , the Utility's outstanding derivative balances were as follows:

| | Commodity Risk | | | |
|---|---|---|---|---|
| (in millions) | Gross Derivative Balance | Netting | Cash Collateral | Total Derivative Balance |
| Current assets – other | $ 91 | $ (10) | $ 1 | **$ 82** |
| Other noncurrent assets – other | 149 | (9) | - | **140** |
| Current liabilities – other | (48) | 10 | - | **(38)** |
| Noncurrent liabilities – other | (101) | 9 | 3 | **(89)** |
| **Total commodity risk** | **$ 91** | **$ -** | **$ 4** | **$ 95** |

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

| | Commodity Risk | | |
|---|---|---|---|
| | For the year ended December 31, | | |
| (in millions) | 2017 | 2016 | 2015 |
| Unrealized gain/(loss) - regulatory assets and liabilities (1) | $ (71) | $ 64 | $ (6) |
| Realized loss - cost of electricity (2) | (27) | (53) | (14) |
| Realized loss - cost of natural gas (2) | (5) | (18) | (10) |
| **Total commodity risk** | **$ (103)** | **$ (7)** | **$ (30)** |

(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 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 i n operating cash flows on the Utility's 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 December 31, 2017 , 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.

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

| | Balance at December 31, | |
|---|---|---|
| (in millions) | 2017 | 2016 |
| Derivatives in a liability position with credit risk-related contingencies that are not fully collateralized | $ (1) | $ (24) |
| Related derivatives in an asset position | - | 19 |
| Collateral posting in the normal course of business related to these derivatives | - | 4 |
| **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 cre dit risk-related contingencies.

**NOTE 10: 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 establ ished 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 in puts 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 . A ssets held in rabbi trusts are held by PG&E Corporation and not the Utility .

| | Fair Value Measur ements | | | | |
|---|---|---|---|---|---|
| | At December 31, 2017 | | | | |
| **(in millions)** | **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 9) | | | | | |
| 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 9) | | | | | |
| 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 deduc ting $ 440 mi llion , primarily related to deferred taxes on appreciation of investment value.

| | Fair Value Measurements | | | | |
|---|---|---|---|---|---|
| | At December 31, 2016 | | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Netting (1)** | **Total** |
| **Assets:** | | | | | |
| Short-term investments | $ 105 | $ - | $ - | $ - | **$ 105** |
| Nuclear decommissioning trusts | | | | | |
| Short-term investments | 9 | - | - | - | **9** |
| Global equity securities | 1,724 | - | - | - | **1,724** |
| Fixed-income securities | 665 | 527 | - | - | **1,192** |
| Assets measured at NAV | - | - | - | - | **14** |
| **Total nuclear decommissioning trusts (2)** | **2,398** | **527** | **-** | **-** | **2,939** |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | 30 | 18 | 181 | (18) | **211** |
| Gas | - | 11 | - | - | **11** |
| **Total price risk management instruments** | **30** | **29** | **181** | **(18)** | **222** |
| Rabbi trusts | | | | | |
| Fixed-income securities | - | 61 | - | - | **61** |
| Life insurance contracts | - | 70 | - | - | **70** |
| **Total rabbi trusts** | **-** | **131** | **-** | **-** | **131** |
| Long-term disability trust | | | | | |
| Short-term investments | 8 | - | - | - | **8** |
| Assets measured at NAV | - | - | - | - | **170** |
| **Total long-term disability trust** | **8** | **-** | **-** | **-** | **178** |
| **TOTAL ASSETS** | **$ 2,541** | **$ 687** | **$ 181** | **$ (18)** | **$ 3,575** |
| **Liabilities:** | | | | | |
| Price risk management instruments (Note 9) | | | | | |
| Electricity | $ 9 | $ 12 | $ 126 | $ (21) | **$ 126** |
| Gas | - | 2 | - | (1) | **1** |
| **TOTAL LIABILITIES** | **$ 9** | **$ 14** | **$ 126** | **$ (22)** | **$ 127** |

(1) Includes the effect of the contractual ability to settle contracts under master netting agreements and margin cash collateral.
(2) Represents amount before deducting $333 million, primarily related to deferred taxes on appreciation of investment value.

**V aluation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabi lities 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 lev els for the years ended December 31, 2017 and 2016 .

***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. N uclear 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 e quity securi ties primarily include i nvestments 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 acti ve 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 Consolidated Balance Sheets. These investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-inc ome 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 agreem ents, 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 obs ervable 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 marke t data are classified as Level 2. Exchange-traded and over-the-counter 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 ma nagement utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from br okers 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 classif ied as Level 3.

**Level 3 Measurements and Sensitivity Analysis**

The Utility's market and credit risk m anagement function, which reports to the Chief Financial Officer, is responsible for determining the fair value of the Utility's price risk manag ement de rivatives. 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 9 above.)

| (in millions) Fair Value Measurement | Fair Value at At December 31, 2017 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

| (in millions) Fair Value Measurement | Fair Value at At December 31, 2016 Assets | Liabilities | Valuation Technique | Unobservable Input | Range [1] |
|---|---|---|---|---|---|
| Congestion revenue rights | $ 181 | $ 35 | Market approach | CRR auction prices | $ (11.88) - 6.93 |
| Power purchase agreements | $ - | $ 91 | Discounted cash flow | Forward prices | $ 18.07 - 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 years ended December 31, 2017 and 2016 , respectively:

| | Price Risk Management Instruments | |
|---|---|---|
| **(in millions )** | **2017** | **2016** |
| Asset (liability) balance as of January 1 | **$ 55** | **$ 89** |
| Net realized and unrealized gains: | | |
| Included in regulatory assets and liabilities or balancing accounts [1] | (13) | (34) |
| **Asset (liability) balance as of December 31** | **$ 42** | **$ 55** |

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

**Financial Instruments**

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

- The fair values of cash , restricted cash , net accounts receivable, short-term borrowings, accounts payable, customer deposits, floating rate senior notes, and the Utility's variable rate pollution control bond loan agreement s approximate their carrying values at December 31, 2017 and 2016 , as they are short-term in nature or ha ve interest rates that reset daily .

- The fair values of the Utility's fixed - rate senior notes and fixed - rate pollution control bond s and PG&E Corporation's fixed - rate senior notes were based on quoted market prices at December 31, 2017 and 2016 .

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 value s):

| | At December 31, | | | |
|---|---|---|---|---|
| | 2017 | | 2016 | |
| **(in millions)** | **Carrying Amount** | **Level 2 Fair Value** | **Carrying Amount** | **Level 2 Fair Value** |
| **Debt (Note 4)** | | | | |
| PG&E Corporation | $ 350 | $ 350 | $ 348 | $ 352 |
| Utility | 17,090 | 19,128 | 15,813 | 17,790 |

***Available for Sale Investments***

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

| (in millions) | | Amortized Cost | | Total Unrealized Gains | | Total Unrealized Losses | | Total Fair Value |
|---|---|---|---|---|---|---|---|---|
| **As of 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** |
| **As of December 31, 2016** | | | | | | | | |
| Nuclear decommissioning trusts | | | | | | | | |
| Short-term investments | $ | 9 | $ | - | $ | - | $ | 9 |
| Global equity securities | | 584 | | 1,157 | | (3) | | 1,738 |
| Fixed-income securities | | 1,156 | | 48 | | (12) | | 1,192 |
| **Total** [(1)] | **$** | **1,749** | **$** | **1,205** | **$** | **(15)** | **$** | **2,939** |

[(1)] Represents amounts before deducting $ 440 million and $333 million at December 31, 2017 and 2016 , respectively, 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 December 31, 2017 |
|---|---|---|
| Less than 1 year | $ | 41 |
| 1–5 years | | 414 |
| 5–10 years | | 352 |
| More than 10 years | | 488 |
| **Total maturities of fixed-income securities** | **$** | **1,295** |

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

| (in millions) | | 2017 | | 2016 | | 2015 |
|---|---|---|---|---|---|---|
| Proceeds from sales and maturities of nuclear decommissioning investments | $ | 1,291 | $ | 1,295 | $ | 1,268 |
| Gross realized gains on securities held as available-for-sale | | 53 | | 18 | | 55 |
| Gross realized losses on securities held as available-for-sale | | (11) | | (26) | | (37) |

**NOTE 11: EMPLOYEE BENEFIT PLANS**

**Pension Plan and Postretirement Benefits Other than Pensions (“PBOP”)**

PG&E Corporation and the Utility sponsor a non-contributory defined benefit pension plan for eligible employees hired before December 31, 2012 and a cash balance plan for those eligible employees hired after this date or who made a one-time election to participate (“Pension Plan”). T he trusts underlying certain of these plans are qualified trusts under the Interna l Revenue Code of 1986, as amended. If certain conditions are met, PG&E Corporation and the Utility can deduct payments made to the qualified trusts, subject to certain limitations. PG&E Corporation’s and the Utility’s funding policy is to contribute tax -deductible amounts, consistent with applicable regulatory decisions and federal minimum funding requirements. Based upon current assumptions and available information, the Utility ’s minimum funding requirements related to its pension plans is zero .

PG &E Corporation and the Utility also sponsor contributory postretirement medical plans for retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. PG&E Corporation and the Utilit y use a fiscal year-end measurement date for all plans.

**Change in Plan Assets, Benefit Obligations , and Funded Status**

The following tables show the reconciliation of changes in plan assets, benefit obligations, and the plans' aggregate funded status for pension benefits and other benefits for PG&E Corporation during 2017 and 2016 :

***Pension Plan***

| **(in millions)** | | **2017** | | **2016** |
|---|---|---|---|---|
| **Change in plan assets:** | | | | |
| **Fair value of plan assets at beginning of year** | **$** | **14,729** | **$** | **13,745** |
| Actual return on plan assets | | 2,380 | | 1,358 |
| Company contributions | | 335 | | 334 |
| Benefits and expenses paid | | (792) | | (708) |
| **Fair value of plan assets at end of year** | **$** | **16,652** | **$** | **14,729** |
| | | | | |
| **Change in benefit obligation:** | | | | |
| **Benefit obligation at beginning of year** | **$** | **17,305** | **$** | **16,299** |
| Service cost for benefits earned | | 472 | | 453 |
| Interest cost | | 714 | | 715 |
| Actuarial (gain) loss | | 1,048 | | 637 |
| Plan amendments | | 10 | | (91) |
| Benefits and expenses paid | | (792) | | (708) |
| **Benefit obligation at end of year [(1)]** | **$** | **18,757** | **$** | **17,305** |
| | | | | |
| **Funded Status:** | | | | |
| Current liability | $ | (7) | $ | (7) |
| Noncurrent liability | | (2,098) | | (2,569) |
| **Net liability at end of year** | **$** | **(2,105)** | **$** | **(2,576)** |

[(1)] PG&E Corporation's accumulated benefit obligation was $ 16.8 billion and $15.6 billion at December 31, 2017 and 2016 , respectively.

***Postretirement Benefits Other than Pensions***

| **(in millions)** | **2017** | **2016** |
|---|---|---|
| **Change in plan assets:** | | |
| **Fair value of plan assets at beginning of year** | **$ 2,173** | **$ 2,035** |
| Actual return on plan assets | 298 | 167 |
| Company contributions | 33 | 52 |
| Plan participant contribution | 87 | 85 |
| Benefits and expenses paid | (171) | (166) |
| **Fair value of plan assets at end of year** | **$ 2,420** | **$ 2,173** |
| | | |
| **Change in benefit obligation:** | | |
| **Benefit obligation at beginning of year** | **$ 1,877** | **$ 1,766** |
| Service cost for benefits earned | 59 | 52 |
| Interest cost | 77 | 76 |
| Actuarial (gain) loss | (49) | 11 |
| Plan amendments | - | 37 |
| Benefits and expenses paid | (157) | (153) |
| Federal subsidy on benefits paid | 3 | 3 |
| Plan participant contributions | 87 | 85 |
| **Benefit obligation at end of year** | **$ 1,897** | **$ 1,877** |
| | | |
| Funded Status: [1] | | |
| Noncurrent asset | $ 553 | $ 368 |
| Noncurrent liability | (30) | (72) |
| **Net asset at end of year** | **$ 523** | **$ 296** |

[1] At December 31, 2017 and 2016 , the postretirement medical plan was in an overfunded position and the postretirement life insurance plan was in an underfunded position.

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

**Components of Net Periodic Benefit Cost**

Net periodic benefit cost as reflected in PG&E Corporation ' s Consol idated Statements of Income was as follows:

***Pension Plan***

| (in millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Service cost | $ 472 | $ 453 | $ 479 |
| Interest cost | 714 | 715 | 673 |
| Expected return on plan assets | (770) | (828) | (873) |
| Amortization of prior service cost | (7) | 8 | 15 |
| Amortization of net actuarial loss | 22 | 24 | 10 |
| **Net periodic benefit cost** | **431** | **372** | **304** |
| Less: transfer to regulatory account [1] | (92) | (34) | 34 |
| **Total e xpense recognized** | **$ 339** | **$ 338** | **$ 338** |

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

***Postretirement Benefits Other than Pensions***

| (in millions) | 2017 | 2016 | 2015 |
|---|---|---|---|
| Service cost | $ 59 | $ 52 | $ 55 |
| Interest cost | 77 | 76 | 71 |
| Expected return on plan assets | (97) | (107) | (112) |
| Amortization of prior service cost | 15 | 15 | 19 |
| Amortization of net actuarial loss | 4 | 4 | 4 |
| **Net periodic benefit cost** | **$ 58** | **$ 40** | **$ 37** |

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

**Components of Accumulated Other Comprehensive Income**

PG&E Corporation and the Utility record unrecognized prior service costs and unrecognized gains and losses related to pension and post-retirement benefits other than pension as components of accumulated other comprehensive income, net of tax . In addition, regulatory adjustments are recorded in the Consolidated Statements of Incom e and Consolidated Balance Sheets to reflect the difference between expense or income calculated in accordance with GAAP for accounting purposes and expense or income for ratemaking purposes, which is based on authorized plan contributions. For pension be nefits, a regulatory asset or liability is recorded for amounts that would otherwise be recorded to accumulated other comprehensive income. For post-retirement benefits other than pension, the Utility generally records a regulatory liability for amounts t hat would otherwise be recorded to accumulated other comprehensive income. As the Utility is unable to record a regulatory asset for these other benefits, the charge remains in accumulated other comprehensive income (loss).

The estimated amounts that wil l be amortized into net periodic benefit cost s for PG&E Corporation in 2018 are as follows:

| (in millions) | Pension Plan | PBOP Plans |
|---|---|---|
| Unrecognized prior service cost | $ (6) | $ 14 |
| Unrecognized net loss | 5 | (5) |
| **Total** | **$ (1)** | **$ 9** |

There were no material differences between the estimated amounts that will be amortized into net period ic benefit costs for PG&E Corporation and the Utility.

### Valuation Assumptions

The following actuarial assumptions were used in determining the projected benefit obligations and the net periodic benefit cost s . The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and ne t benefit cost.

| | Pension Plan | | | PBOP Plans | | |
|---|---|---|---|---|---|---|
| | December 31, | | | December 31, | | |
| | 2017 | 2016 | 2015 | 2017 | 2016 | 2015 |
| **Discount rate** | 3.64 % | 4.11 % | 4.37 % | 3.60- 3.67 % | 4.05 - 4.19 % | 4.27 - 4.48 % |
| **Rate of future compensation increases** | 3.90 % | 4.00 % | 4.00 % | - | - | - |
| **Expected return on plan assets** | 6.20 % | 5.30 % | 6.10 % | 3.30 - 7.10 % | 2.80 - 6.00 % | 3.20 - 6.60 % |

The assumed health care cost trend rate as of December 31, 2017 was 6.8 % , decreasing gradually to a n ul timate trend rate in 2025 and beyond of approximately 4.5 % . A one-percentage-point change in assumed health care cost trend rate would have the following effects:

| (in millions) | One-Percentage-Point Increase | One-Percentage-Po int Decrease |
|---|---|---|
| Effect on postretirement benefit obligation | $ 128 | $ (129) |
| Effect on service and interest cost | 9 | (10) |

Expected rates of return on plan assets were developed by determining projected stock and bond returns and then applying these returns to the target asset allocations of the employee benefit plan trusts, resulting in a weighted average rate of return on pl an assets. Returns on fixed-income debt investments were projected based on real maturity and credit spreads added to a long-term inflation rate. Returns on equity investments were estimated based on estimates of dividend yield and real earnings growth a dded to a long-term inflation rate . For the pension plan, the assumed return of 6.2 % compares to a ten-year actual return of 7.8 %. The rate used to discount pension benefits and ot her benefit s was based on a yield curve developed from market data of over approximately 623 Aa-grade non-callable bonds at December 31, 2017 . This yield curve has discount rates that vary based on the duration of the obligations. The estimated future cash flows for the pension benefits and other benefit obligations were matched to the corresponding rates on the yield curve to derive a weighted average dis count rate.

### Investment Policies and Strategies

The financial position of PG&E Corporation's and the Utility's funded status is the difference between the fair value of plan assets and projected benefit obligations. Volatility in funde d status occurs wh en asset values change differently from liability values and can result in fluctuations in costs in financial reporting , as well as the amount of minimum contributions required under the Employee Retirement Income Security Act of 1974, as amended . P G&E Co rporation's and the Utility's investment policies and strategies are designed to increase the ratio of trust assets to plan liabilities at an acceptable level of funded status volatility.

The trusts ' asset allocations are meant to manage volatility, reduce costs, and diversify its holdings . Interest rate, credit, and equity risk are the key determinants of PG&E Corporation's and the Utility's funded status volatility. In addition to affecting the trusts' fixed income portfolio market values, interes t rate changes also influence liability valuations as discount rates move with current bond yields. To manage volatility , PG&E Corporation's and the Utility's trust s hold significant allocations in long maturity fixed-income investments . A lthough they co ntribute to funded status volatility, equity investments are held to reduce long-term funding costs due to their higher expected return. Real assets and absolute return investments are held to diversify the trust 's holdings in equity and fixed-income inve stments by exhibiting returns with low correlation to the direction of these markets. R eal assets include commodities futures, global REITS, and global listed infrastructure equities. Absolute return investments include hedge fund portfolios .

Derivative instruments such as equity index futures are used to meet target equity exposure. Derivative instruments, such as equity index futures and U.S. treasury futures, are also used to rebalance the fixed income/equity allocation of the pension's portfolio. F oreign currency exchange contracts are used to hedge a portion of the non U.S. dollar exposure of global equity investments.

The target asset allocation percentages for major categories of trust assets for pension and other benefit plans are as follows:

| | Pension Plan | | | PBOP Plans | | |
|---|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 | 2017 | 2016 |
| Global equity | 29 % | 27 % | 25 % | 33 % | 32 % | 32 % |
| Absolute return | 5 % | 5 % | 5 % | 3 % | 3 % | 3 % |
| Real assets | 8 % | 10 % | 10 % | 6 % | 7 % | 7 % |
| Fixed income | 58 % | 58 % | 60 % | 58 % | 58 % | 58 % |
| **Total** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** | **100 %** |

PG&E Corporation and the Utility apply a risk management framework for managing the risks associated with employee benefit plan trust assets. The guiding principles of this risk management framework are the clear articulation of roles an d responsibilities, appropriate delegation of authority, and proper accountability and documentation. Trust investment policies and investment manager guidelines include provisions designed to ensure prudent diversification, manage risk through appropriat e use of physical direct asset holdings and derivative securities, and identify permitted and prohibited investments.

**Fair Value Measurements**

The following tables present the fair value of plan assets for pension and other benefits plans by major asset category at December 31, 2017 and 2016 .

| | Fair Value Measurements | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | At December 31, | | | | | | | |
| | 2017 | | | | 2016 | | | |
| **(in millions)** | **Level 1** | **Level 2** | **Level 3** | **Total** | **Level 1** | **Level 2** | **Level 3** | **Total** |
| **Pension Plan:** | | | | | | | | |
| Short-term investments | $ 287 | $ 424 | $ - | **$ 711** | $ 364 | $ 369 | $ - | **$ 733** |
| Global equity | 1,292 | - | - | **1,292** | 996 | - | - | **996** |
| Real assets | 499 | - | - | **499** | 610 | - | - | **610** |
| Fixed-income | 1,916 | 5,520 | 4 | **7,440** | 1,754 | 4,774 | 5 | **6,533** |
| Assets measured at NAV | - | - | - | **6,818** | - | - | - | **5,950** |
| **Total** | **$ 3,994** | **$ 5,944** | **$ 4** | **$ 16,760** | **$ 3,724** | **$ 5,143** | **$ 5** | **$ 14,822** |
| **PBOP Plans:** | | | | | | | | |
| Short-term investments | $ 31 | $ - | $ - | **$ 31** | $ 33 | $ - | $ - | **$ 33** |
| Global equity | 141 | - | - | **141** | 115 | - | - | **115** |
| Real assets | 55 | - | - | **55** | 70 | - | - | **70** |
| Fixed-income | 163 | 757 | - | **920** | 150 | 656 | - | **806** |
| Assets measured at NAV | - | - | - | **1,281** | - | - | - | **1,153** |
| **Total** | **$ 390** | **$ 757** | **$ -** | **$ 2,428** | **$ 368** | **$ 656** | **$ -** | **$ 2,177** |
| **Total plan assets at fair value** | | | | **$ 19,188** | | | | **$ 16,999** |

In addition to the total plan assets disclosed at fair value in the table above, the trusts had other net assets of $ 116 million and $97 million at December 31, 2017 and 2016 , resp ectively, comprised primarily of cash, accounts receivable, deferred taxes, and accounts payable.

**Valuation Techniques**

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tabl e above. All investments that are valued using a NAV per share can be redeemed quarterly with a notice not to exceed 90 days.

***Short-Term Investments***

Short-term investments consist primarily of commingled funds across government, credit, and asset-backed sectors. These securities are categorized as Level 1 and Level 2 assets.

***Global Equity***

The global equity category include s investments in common stock and equity-index futures . Equity investments in common stock are actively traded on public exchanges and are therefore considered Level 1 assets. These equity investments are generally valued based on unadjusted prices in active mar kets for identical securities. Equity-index futures are valued based on unadjusted prices in active markets and are Level 1 assets .

***Real Assets***

The real asset category includes portfolios of commodity futures, global REITS and global listed infrastructure equities . The commodity futures, global REITS, and global listed infrastructure equities are actively traded on a publ ic exchange and are therefore considered Level 1 assets.

***Fixed-Income***

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 fa ir value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and i ssuer 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 trusts 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 Consolidated Balance Sheets. These inv estments 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, asset-backed securities, and private real estate funds. The re are no restrictions on the terms and conditions upon which the investments may be redeemed.

**Transfers Between Levels**

Any transfers between levels in the fair value hierarchy are recognized as of the en d of the reporting period. No material transfer s between levels occurred in the years ended December 31, 2017 and 2016 .

**Level 3 Reconciliation**

The following table is a reconciliation of changes in the fair value of instruments for the pension p lan that have been classified as Level 3 for the years ended December 31, 2017 and 2016 :

| **(in millions)**<br>**For the year ended December 31, 2017** | **Fixed-Income** |
|---|---|
| Balance at beginning of year | $ 5 |
| Actual return on plan assets: | |
| Relating to assets still held at the reporting date | (1) |
| Relating to assets sold during the period | - |
| Purchases, issuances, sales, and settlements: | |
| Purchases | 3 |
| Settlements | (3) |
| **Balance at end of year** | **$ 4** |

| **(in millions)**<br>**For the year ended December 31, 2016** | **Fixed-Income** |
|---|---|
| Balance at beginning of year | $ 3 |
| Actual return on plan assets: | |
| Relating to assets still held at the reporting date | 3 |
| Relating to assets sold during the period | - |
| Purchases, issuances, sales, and settlements: | |
| Purchases | - |
| Settlements | (1) |
| **Balance at end of year** | **$ 5** |

There were no material transfers out of Level 3 in 2017 and 2016 .

**Cash Flow Information**

***Employer Contributions***

PG&E Corporati on and the Utility contributed $ 335 million to the pension benefit plans and $ 33 mill ion to the other benefit plans in 2017 . These contributions are consistent with PG&E Corporation’s and the Utility’s funding policy, which is to contribute amounts that are tax-deductible and consistent with applicable regulatory de cisions and federal minimum funding requirements. None of these pension or other benefits were subject to a minimum funding requirement requiring a cash contribution in 2017 . The Utility’s pension benefits met all the funding requi rements under the Employee Retirement Income Security Act . PG&E Corporation and the Utility expect to make total contributions of approximately $ 327 million and $ 24 million to the pension plan and other postretirement benefit plans, respectively, for 2018 .

***Benefits Payments and Receipts***

As of December 31, 2017 , the estimated benefits expected to be paid and the estimated federal subsidies expected to be receive d in each of the next five fiscal years, and in aggregate for the five fiscal years thereafter, are as follows:

| (in millions) | Pension Plan | PBOP Plans | Federal Subsidy |
|---|---|---|---|
| 2018 | $ 712 | $ 83 | $ (8) |
| 2019 | 811 | 87 | (9) |
| 2020 | 850 | 91 | (9) |
| 2021 | 886 | 95 | (10) |
| 2022 | 920 | 100 | (3) |
| Thereafter in the succeeding five years | $ 5,002 | $ 508 | $ (15) |

There were no material differences between the estimated benefits expected to be paid by PG& E Corporation and paid by the Utility for the years presented above. There were also no material differences between the estimated subsidies expected to be received by PG&E Corporation and received by the Utility for the years presented above.

**Retirement Savings Plan**

PG&E Corporation sponsors a retirement savings plan, which qualifies as a 401(k) defined contribution benefit plan under the Internal Revenue Code 1986, as amended. This plan permits eligible employees t o make pre-tax and after-tax contrib utions into the plan, and provide for employer contributions to be made to eligible participants. Total expenses recognized for defined contribution benefit plans reflected in PG&E Corporation's Consolidated Statements of Income were $ 103 million, $97 million, and $89 million in 2017 , 2016 , and 2015 , respectively.

There were no materi al differences between the employer contribution expense for PG&E Corporation and the Utility for the years presented above.

**NOTE 12: RELATED PARTY AGREEMENTS AND TRANSACTIONS**

The Utility and other subsidiaries provide and receive various services to and from their parent, PG&E Corporation, and among themselves. The Utility and PG&E Corporation exchange administrative and professional services in support of operations. Services provided directly to PG&E Corporation by the Utility are priced at the higher of fully loaded cost (i.e., direct cost of good or service and allocation of overhead costs) or fair market value, depending on the nature of the services. Services provided directly to the Utility by PG&E Corporation are general ly priced at the lower of fully loaded cost or fair market value, depending on the nature and value of the services. PG&E Corporation also allocates various corporate administrative and general costs to the Utility and other subsidiaries using agreed-upon allocation factors, including the number of employees, operating and maintenance expenses, total assets, and other cost allocation methodologies. Management believes that the methods used to allocate expenses are reasonable and meet the reporting and acc ounting requirements of its regulatory agencies.

The Utility ' s significant related party transactions were :

| | Year Ended December 31, | | |
|---|---|---|---|
| (in millions) | 2017 | 2016 | 2015 |
| **Utility revenues from:** | | | |
| Administrative services provided to PG&E Corporation | $ 8 | $ 7 | $ 6 |
| **Utility expenses from:** | | | |
| Administrative services received from PG&E Corporation | $ 65 | $ 74 | $ 53 |
| Utility employee benefit due to PG&E Corporation | 73 | 91 | 82 |

At December 31, 2017 and 2016 , the Utility had receivable s of $ 20 million and $ 18 m illion, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payable s of $ 22 million and $22 million, respectively, to PG&E Corporation included in accounts payable – other on the Utility's Consolidated Balance Sheets.

**NOTE 13: CONTINGENCIES AND COMMITMENTS**

PG &E Cor poration 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 prob able that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount with in the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss con tingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a parti cular matter. PG&E Corporation's and the Utility's provision for loss and expense excludes anticipated legal costs, which are expensed as incurred . The Utility also has substantial financial commitments in connection with agreements entered into to suppo rt its operating activities. See "Purchase Commitments" below. PG&E Corporation has financial commitments described in "Other Commitments" below. PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows may be mate rially 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 th e wildfires, there were 21 major wildfires in California that, in total, burned over 245,000 acres, resulted in 43 fatalities, and destroyed an estimated 8,900 structures. Subsequently, the number of fatalities increased to 44.

The Utility incurred $ 219 million in costs for service restoration and repair to the Utility's facilities (including $97 million in capital expenditures) through December 31, 2017 in connection with these fires. While the Utility believes that such costs are recoverable through C EMA , 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 fires are being investigated 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 pr ogressed. The CPUC's SED also 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, inve stigation 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 facilitie s, 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 investigation is complete.

As of January 31, 2018 , the Utility had submitted 22 e lectric incident reports to the CPUC associated with the Northern California wildfires where Cal Fire 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 in vestigations into the fires are ongoing.

If the Utility's facilities, such as its electric distribution and transmission lines, are determined to be the cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damage, 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 c ourts 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 benefitted from su ch 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 co st 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 t o such claims for property damage, 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 Util ity 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 preliminary stages of investigations and the uncertainty as to the causes of the fires, PG&E Corpor ation 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 material. PG&E Corporation and the Utility currently are unable to reasonably estimate the amount of losses (or range of amounts) that they could incur given the preliminary s tages 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 Octo ber 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 20 17 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 Departmen t 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 suppr ession 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 lia bility could be higher than the approximately $10 billion estimated in respect of 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 f inancial condition, results of operations, liquidity, and cash flows could be materially affected.

As of January 31, 2018 , PG&E Corporation and the Utility are aware of 111 lawsuits, six of which seek to be certified as class action s , that have been fil ed 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 Corpo ration'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 wrong ful 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 ha ve filed three 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. 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 a nd 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 Francisc o 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 Judici al Council of California accepted the coordination motion judge's recommendation and assigned the coordinated proceeding to San Francisco. The first case management conference is scheduled for February 27, 2018.

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 Corp oration and the Utility . PG&E Corporation and the Utility are identified as nominal defendants in that action. Motions to consolidate the two lawsuits, appoint lead plaintiffs' counsel, and enter a case schedule are currently pending.

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 inve stigation 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 $800 million. 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 and the Utility could apply for cost recovery. 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 num ber of years thereafter to collect. Further, SB 819, introduced in the California Senate in January 2018, if it becomes law, would prohibit utilities from recovering costs in excess of insurance resulting from damages caused by such utilities' facilities, if the CPUC determines that the utility did not reasonably construct, maintain, manage, control, or operate the facilities. 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 repo rt, 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 p ine tree contacted the Uti lity'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 Californ ia for Sacramento County. Subrogation insurers also filed a separate master complaint on the same date. The California Judicial Council had previously authorized the coordination of all cases in Sacramento County. As of December 3 1 , 2017, 77 known compl aints 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 plaintif fs representing approximately 2 ,030 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 doc trine of inverse condemnation and negligence theor y of liability. Plaintiffs also seek punitive damages. As of December 31, 2017, several plaintiffs have dismissed the Utility's two vegetation management contractors. The number of individual complaints and plaintiffs may still increase in the future , because the statute of limitations for property damages 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 the State of California, County of Calaveras, seeking to recover $87 million for its costs incurred on the theory t hat the Utility and its vegetation management contractors were negligent, among other claims. On July 31, 2017, Cal Fire dismissed its complaint against Tree's, Inc., one of the Utility's vegetation contractors. The Utility and Cal Fire are currently eng aged in a mediation process.

Further , in May 2017, the OES indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $190 million. This claim would include costs incurred by the OES for tree and debr is removal, infrastructure damage, erosion control, and other claims related to the Butte fire. Also, in June 2017, the County of Calaveras indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $85 m illion. This claim would include costs that the County of Calaveras incurred or expects to incur for infrastructure damage, erosion control, and other costs related to the Butte fire.

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 con scious 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 Appeals challenging w hat the Utility believes is a novel theory of punitive damages liability. The Court of Appeals 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 is seeking expedited review of the motion.

On June 22, 2017, the Superior Court for the County of Sacramento ruled on a motion of several plaintiffs and found that the doctrine of inv erse 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 c ondemnation liability through rate increases . While the ruling is binding only between the Utility and the plaintiffs in the coordination proceeding, 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 tha t it will not automatically allow utilities to spread inverse condemnation losses through rate increases. The motion is set for hearing on March 15, 2018.

*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 were 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, increased from the $750 million previously estimated as of December 31, 2016, in connection with the Butte fire. The Utility's updated estimate resulted primarily from an increase in the number of claims filed against the Utility and experience to date in resolving claims. This amount is based on updated assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of tree s 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 whi ch the Utility could be liable. In addition, w hile this amount i ncludes the Utility's assumptions about fire suppression costs (including its assessment of the Cal Fire loss), it does not include any significant portion of the estimated claims from the OES and the County of Calaveras. The Utility still does not have s ufficient information to reasonably estimate the probable loss it may have for these additional claims.

The Utility currently is unable to reasonably estimate the upper end of the range of losses due to the uncertainty of pending legal motions related to the applicability of inverse condemnation and punitive damages and because it has insufficient information on the claims of over 1,000 households and the claims from the OES and the County of Calaveras. The process for estimating costs associated with clai ms 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 med iation and settlement process, review of potential claims from the OES and the County of Calaveras, outcomes of future court or jury decisions, and information about damages, including punitive damages, that the Utility could be liable for, management esti mates and assumptions regarding the financial impact of the Butte fire may result in materia l 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 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** |

[1] As of December 31 , 2017 the Utility entered into settlement agreements in connection with the Butte fire corresponding to approximat ely $ 624 million of which $ 539 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 $ 87 million in connection with the Butte fire. For the year ended December 31, 2017, the Utility has incurred legal expenses in connection with the Butte fire of $60 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 $9 22 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 December 31, 2017, the Utility recorded $ 922 m illion 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 , in the year ended December 31, 2017, the Utility received $53 million of reimbursements from the insurance polic ies of one of its vegetation management contractors ( excluded from t he table below) . Recoveries of additional amounts under the insurance pol icies of the Utility's vegetation management contractor s , including policies where the Utility is listed as an add itional insured, are uncertain.

The following table presents changes in the insurance receivable since December 31, 2015. The balance for th e insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's 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** |

In January 2018, the Utility received another $75 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 affe cted in the reporting periods during which additional charges are recorded, depending on whether the Utility is able to record or collect insurance recoveries in amounts sufficient to offset such additional accruals.

*Regulatory Citations*

On April 25, 201 7, 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 the gray pine 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.

***Enforceme nt 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 coop era ted with those investigations. It is uncertain whether any charges will be brought against the Utility as a result of these investigations.

***CPUC Matters***

*Order Instituting an Investigation into Compliance with Ex Parte Communication Rules*

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

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

On March, 28, 2017, the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility jointly submitted to the CPUC a settlement agreement in connection wi th the OII into the Utility's compliance with the CPUC's ex parte communication rules. On September 1, 2017, the assigned administrative law judge issued a PD in this proceeding adopting, with one modification, the settlement agreement jointly submitted to the CPUC on March 28, 2017, by the Utility, the Cities of San Bruno and San Carlos, the ORA, the SED, and TURN.

If adopted, the PD would increase the payment to the California General Fund , relative to the settlement agreement, from $1 million to $12 mil lion resulting 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 to tal 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 emplo yee 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.

On September 21, 2017, the Utility submitted a motion to the CPUC ac cepting the proposed modification of the settlement agreement to increase the Utility's payment to the California General Fund from $1 million to $12 million. Further, the Utility also reported that it has identified several communications that appear to r aise issues similar to other communications that are part of this proceeding.

On November 1, 2017, the Utility filed a status report advising the CPUC that the Utility and the non-Utility parties to the settlement agreement were unable to reach an agreem ent with respect to how to proceed regarding the communications that the Utility reported to the CPUC on September 21, 2017. Also on November 1, 2017, the non-Utility parties to the settlement requested that the CPUC approve the settlement, as modified by the PD, and open a second phase of the OII to investigate and consider appropriate sanctions for the new communications reported by the Utility on September 21, 2017, and others that may be discovered.

On November 30, 2017, the CPUC issued a decision ex tending the statutory deadline to June 29, 2018 to resolve the proceeding. The CPUC stated that an extension of the statutory deadline was necessary to allow the assigned administrative law judge time to prepare the revised decision and to open and resolve a second phase of this proceeding.

The Utility is unable to predict the outcome of this proceeding.

At December 31, 2017, PG&E Corporation's and the Utility's Consolidated Balance Sheets include a $24 million accrual for the amounts payable to the Cali fornia General Fund and the Cities of San Bruno and San Carlos. In accordance with accounting rules, adjustments related to revenue requirements would be recorded in the periods in which they are incurred.

*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 s et 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 tha t 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 fut ure 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 fact ors 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 g as 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 find ings, 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 discreti on whether to iss ue a penalty for each violation.

The SED has discretion whether to issue a penalty for each violation, but if it assesses a penalty for a violation, it is required to impose the maximum statutory penalty of $50,000, with an administrativ e 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 c ompliance, 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, t he SED has exercised broad discretion in determining whether violations are continuing and the amount of penalties to be imposed. In the past, t he 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 viola tions of electric and natural gas laws and regulations.

***Other Matters***

*Other Contingencies*

PG&E Corporation and the Utility are subject to various claims, lawsuits and regulatory proceeding s 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 $86 million at December 31, 2017 and $45 million at Decembe r 31, 2016. These amounts are included in O ther current liabilities in the 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**

PG&E Corporation and the Utility record a charge when it is both probable that costs incurred for recently completed plant will not be recoverable through rates and the amount of disallowance can be reasonably estimated. Capital disallowance s are reflected in operating and maintenance expenses in the Consolidated Statements of Income . Disallowances as a result of the CPUC's June 2016 final phase one decision and December 2016 final phase two decision in the Utility's 2015 GT&S rate case , the Utility's Pipeline Safety Enhancement Plan, and CPUC's final decision on the closure of Diablo Canyon are discussed below.

*2015 GT&S Rate Case Disallowance of Capital Expenditures*

On June 23, 2016, the CPUC approved a final phase one decision in the Ut ility'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. The decision permanently disallowed $120 million of that amount and ordered that the remaini ng $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 decision also established various cost caps that will increase the risk of overspend over the current ra te case cycle including new one-way balancing accounts. As a result, in 2016, the Utility incurred charges of $219 million for capital expenditures that the Utility believes are probable of disallowance based on the decisi on. This included $134 million for 2011 through 2014 capital expenditures in excess of adopted amounts and $85 million for the Utility's estimate of 2015 through 2018 capital expenditures that are probable of exceeding authorized amounts. Additional charges may be required in the future b ased 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 Expenditures Relating to Pipeline Safety Enhancement Plan*

The CPUC has authorized the Utility to collect $ 766 million for recovery of PSEP capital costs. As of December 31, 2017 , th e Utility has spent $1.38 billion on PSEP-related capital costs, of which $665 million was expensed in previous years for costs that are expected t o exceed the authorized amount. The Utility expects the remaining PSEP work to co ntinue throughout 2018. The Utility would be required to record charges in future periods to the extent PSEP-related capital costs are higher than currently expected.

*Capital Expenditures Relating to the D iablo Canyon Power Plant*

On January 11, 2018, the CPUC issued a final decision adopting the settlement agreement jointly submitted to the CPUC in May 2017 related to the recovery of license renewal costs and cancelled project costs within the Utility's ap plication to retire Diablo Canyon. The final decision allows for recovery from customers of $18.6 million of the total license renewal project cost of $53 million evenly over an 8-year period beginning January 1, 2018. Related to cancelled project costs, the decision allows for recovery from customers of 100% of the direct costs incurred prior to June 30, 2016 and 25% recovery of direct costs incurred after June 30, 2016. During the year ended December 31 , 2017, th e Utility incurred charges of $47 million related to the Diablo Canyon capital expenditures settlement agreement, of which $24 million is for cancelled projects and $23 million is for disallowed license renewal costs. The Utility does not expect to incur additional charges as a result of the CPUC 's final decision, other than additional project cancellation costs that the Utility does not expect to be material.

**Environm ental Remediation Contingencies**

Given the complexities of the legal and regulatory environment and the inherent uncertainties involved in the early stages of a remediation project, the process for est imating remediation liabilities requires significant judgment. The Utility records an environmental remediation liability w hen the site assessments indicate that remediation is probable and the Utility can reasonably estimate the loss or a range of probable amounts. The Utility records an environmental remediation liability based on the lower end of the range of estimated pro bable costs, unless an amount within the range is a better estimate than any other amount. Key factors that inform the development of estimated costs include site feasibility studies and investigations, applicable remediation actions, operations a nd maint enance activities, post- remediation monitoring, and the cost of technologies that are expected to be approved to remediate the site . Amounts recorded are not discounted to their present value. The Utility's environmental remediation liability is primaril y included in non-current liabilities on the Consolidated Balance Sheets and is composed of the following:

| | Balance at | |
|---|---|---|
| **(in millions)** | **December 31 2017** | **December 31, 2016** |
| Topock natural gas compressor station | $ 334 | $ 299 |
| Hinkley natural gas compressor station | 147 | 135 |
| Former manufactured gas plant sites owned by the Utility or third parties (1) | 320 | 285 |
| Utility-owned generation facilities (other than fossil fuel-fired), other facilities, and third-party disposal sites (2) | 115 | 131 |
| Fossil fuel-fired generation facilities and sites (3) | 123 | 108 |
| **Total environmental remediation liability** | **$ 1,039** | **$ 958** |

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

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 stor age, recycling, and disposal of potentially hazardous substances are subject to requirements issued by the state and federal regulatory agencies under the federal Resource Conservation and Recovery Act and/or other 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 qu ality control boards, and various other federal, state, and local agencies.

The Utility's environmental remediation liability at December 31, 2017 reflects its best estimate of probable future costs associated with its final remediation plan. Future costs will depend on many factors, including the extent of work to implement final remediation plans and the Utility's required time frame for remediat ion. 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 December 31, 2017 , the Utility expected to recover $ 725 million of its environmental remediation liabil ity through various ratemaking mechanisms authorized by the CPUC.

***Natural Gas Co mpressor 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 DTSC and the DOI. In November 2015, the Utility submitted its final remediation design to the agencies for approval. The Utility's design proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium int o 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 requir ed 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 $ 289 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 i mplementing interim 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 r egulatory 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 final clean-up and abatement order to contain and remediate the u nderground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order requires setting plume capture requirements, requires establishing a monitoring and reporting program, and finalizes deadlines for the Utility to meet interim cleanup targets. The 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 $ 145 million if the extent of contamination or necessary remediation is greater than anticipated. T he costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

***Former Manufactured Gas Plants ("MGPs ")***

Former m anufactured gas plants 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 at the manufactured gas plants 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 $ 343 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 .

***Utili ty-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 Util ity-owned generation facilities and third-party disposal sites may increase by as much as $ 145 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 plan t 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 w i th the fossil fuel-fired sites will not be recovered through rates.

**Nuclear Insurance**

The Utility is a member of NEIL, which is a mutual insurer owned by utilities with nuclear facilities. NEIL provides insurance coverage for property damages and business interruption losses incurred by the Utility if a nuclear event were to occur at the Utility's two nuclear generating units at Diablo Canyon and the retired Humboldt Bay Unit 3. NEIL provides property damage and business interruption coverage of up to $ 3.2 billion per nuclear incident and $2.6 billion per non-nuclear incident for Diablo Canyon . Humboldt Bay Unit 3 has up to $ 131 million of coverage for nuclear and non-nuclear property damages.

NEIL also provide s coverage for damages caused by acts of terrorism at nuclear power plants. Certain acts of terrorism may be "certified" by the Secretary of the Treasury. If damages are caused by certified acts of terrorism, NEIL can obtain compensation from the federal government and will provide up to its full policy limit of $ 3.2 billion for each insured loss. In contrast, NEIL would treat all non-certif ied terrorist acts occurring within a 12-month period against one or more commercial nuclear power plants insured by NEIL as one event and the owners of the affected plants would share the $ 3.2 billion policy limit amount.

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

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of December 31, 2017, the current maximum aggregate annual retrospect ive premium obligation for the Utility would be approximately $ 57 million. EMANI provides $200 million for any one accident and in the annual aggregate excess of the combined amount recoverable under the Utility's NEIL policies. If EMANI losses in any po licy year exceed accumulated funds, the Utility could be subject to a retrospective assessment of approximately $ 3 million, as of December 31, 2017.

Under the Price-Anderson Act, public liability claims that arise from nuclear incid ents that occur at Diablo Canyon, and that occur during the transportation of material to and from Diablo Canyon are limited to $ 13.5 billion. The Utility purchased the maximum available public liability insurance of $ 450 million for Diablo Canyon. The balance of the $ 13.5 billion of liability protection is provided under a loss-sharing program among utilities owning nuclear reactors. The Utility may be assessed up to $ 255 million per nuclear incident under this program, with payments in each year limited to a m aximum of $38 million per incident. Both the maximum assessment and the maximum yearly assessment are adjusted for inflation at least every five years. The next scheduled adjustment is due on or before September 10, 2018 .

The Price-Anderson Act does not apply to claims that arise from nuclear incidents that occur during shipping of nuclear material from the nuclear fuel enricher to a fuel fabricator or that occur at the fuel fabricator's facility. The Utility has a separate policy that provides coverage for claims arising from some of these incidents up to a maximum of $ 450 million per incident. In addition, the Utility has $ 53 million of liability insurance for Humboldt Bay Unit 3 and has a $ 500 million indemnification from the NRC for public liability arising from nuclear incidents, covering liabilities in excess of the lia bil ity insurance.

**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 bet ween 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 electr icity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims agains t these electricity suppliers. Under these settlement agreements, a mounts 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 FER C. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclus ion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

At December 31, 2017 and December 31, 2016, respectively, the Consolidated Balance Sheets reflected $ 243 million and $ 236 million in net claims within Disputed claims and customer refunds. The Utility is uncertain when or how the remaining net disputed claims liability will be resolved.

**Purchase Commitments**

The following table shows the undiscounted future expected obligations under power purchase agreements that have been approved by the CPUC and have met specified construction milestones as well as undiscounted future expected paymen t obligations for natural gas supplies, natural gas transportation, natural gas storage, and nuclear fuel as of December 31, 2017 :

| | **Power Purchase Agreements** | | | | | |
|---|---|---|---|---|---|---|
| **(in millions)** | **Renewable Energy** | **Conventional Energy** | **Other** | **Natural Gas** | **Nuclear Fuel** | **Total** |
| 2018 | $ 2,150 | $ 718 | $ 280 | $ 388 | $ 96 | $ 3,632 |
| 2019 | 2,193 | 706 | 221 | 167 | 102 | 3,389 |
| 2020 | 2,188 | 686 | 175 | 148 | 143 | 3,340 |
| 2021 | 2,168 | 588 | 153 | 93 | 70 | 3,072 |
| 2022 | 1,975 | 512 | 143 | 93 | 60 | 2,783 |
| Thereafter | 26,005 | 657 | 526 | 357 | 151 | 27,696 |
| **Total purchase commitments** | **$ 36,679** | **$ 3,867** | **$ 1,498** | **$ 1,246** | **$ 622** | **$ 43,912** |

### *Third-Party Power Purchase Agreements*

In the ordinary course of business, the Utility enters into various agreements , including renewable energy agreements, QF agreements, and other power purchase agreements to purchase power and electric capacity . The price of purchased power may be fixed or variable. Variable pricing is generally based on the current market price of either natural gas or el ectricity at the date of delivery.

*Renewable Energy Power Purchase Agreement s* . In order to comply with C alifornia's RPS requirements, the Utility is required to deliver renewable energy to its customers at a gradually increasing rate. The Utility has entered into various agreements to purchase renewable energy to help meet California's requirement . The Uti lity's obligations under a significant portion of these agreements are contingent on the third party's construction of new generation facilities, which are expected to grow. As of December 31, 2017, renewable energy contracts expire at various dates betwe en 2018 and 2043 .

*Conventional Energy Power Purchase Agreements* . The Utility has entered into power purchase agreements for conventional generation resources, which inclu de tolling agreements and resource adequacy agreements . The Utility's obligation under a portion of these agreements is contingent on the third part ies ' development of new generation facilit ies to provide capacity and energy products to the Utility . As o f December 31, 2017, these power purchase agreements expire at various dates between 2018 and 2033 .

*Other Power Purchase Agreements.* The Utility has entered into agreemen ts to purchase energy and capacity with independent power producers that own generation facilities that meet the definition of a QF under federal law. Several of these agreements are treated as capital leases. At December 31, 2017 and 2016 , net capital leases reflected in property, plant, and equipment on the Consolidated Balance Sheets were $ 18 million and $35 million including accumulated amortization of $ 143 million and $ 148 millio n, respectively. The present value of the future minimum lease payments due under these agreements included $ 11 million and $17 million in Current Liabilities and $ 7 million and $18 million in Noncurrent Liabilities on the Consolidated Balance Sheet, respectively. As of December 31, 2017 , QF contracts in operation expire at various dates between 2018 and 2028 . In addition, t he Utility has agreements with various irrigation districts and w ater agenci es to purchase hydroelectric power.

The costs incurred for all power purchase s and electric capacity amounted to $ 3.3 billion in 2017, $ 3.5 billion in 2016, and $ 3.5 billion in 2015.

### *Natural Gas Supply, Transportation, and Storage Commitments*

The Utility purchases natural gas directly from producers and marketers in both Canada and the United States to serve its core customers and to fuel its owned-generation facilities . The Utility also contracts for natural gas transportation from the points at which the Utility takes delivery (typically in Canada , the US Rocky Mountain supply area, and the southwestern United States) to the points at which the Utility's natural gas transportation system begins. These agreements expire at various dates between 2018 and 2026 . In addition, the Utility has cont racted for natural gas storage services in northern California in order to more reliably meet customers' loads. Costs incurred for natural gas purchases, natural gas transportation services, and natural ga s storage, which include contracts with terms of l ess than 1 year, amounted to $ 0.9 billion in 2017 , $0.7 billion in 2016 , and $0.9 billion in 2015 .



Nuclear Fuel Agreements

The Utility has entered into several purchase agreements for nuclear fuel. These agreements expire at various dates between 2018 and 2025 and are intended to ensure long-t erm nuclear fuel supply. T he Utility relies on a number of international producers of nuclear fuel in order to diversify its sources and provide security of supply. Pricing terms are also diversified, ranging from market-based prices to base prices that are escalated using published indices.

Payments for nuclear fuel amounted to $ 83 milli on in 2017 , $ 100 million in 2016 , and $ 128 million in 2015 .

**O ther Commitments**

PG&E Corporation and t he Utility have other commitments related to operating leases (primarily office facilities and land), which expire at various date s between 2018 and 2052 . At December 31, 2017 , the future minimum payments related to these commitments were as follows:

| **(in millions)** | | **Operating L eases** |
|---|---|---|
| 2018 | $ | 44 |
| 2019 | | 41 |
| 2020 | | 40 |
| 2021 | | 36 |
| 2022 | | 27 |
| Thereafter | | 138 |
| **Total minimum lease payments** | **$** | **326** |

Payments for other commitments related to operating leases amounted to $ 45 million in 2017 , $ 43 million in 2016 , and $ 41 million in 2015 . Certain leases on office facilities contain escalation clauses requiring annual increases in rent. The rental s payable under these leases may increase by a fixed amount each year, a percentage of increase over base year, or the consumer price index. Most leases contain extension operations ranging between one and five years.

## QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

| | Quarter ended | | | |
|---|---|---|---|---|
| (in millions, except per share amounts) | December 31 | September 30 | June 30 | March 31 |
| **2017** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues [1] | $ 4,100 | $ 4,517 | $ 4,250 | $ 4,268 |
| Operating income | 429 | 899 | 748 | 880 |
| Income tax provision [2] | 108 | 160 | 134 | 109 |
| Net income [3] | 118 | 553 | 410 | 579 |
| Income available for common shareholders | 114 | 550 | 406 | 576 |
| Comprehensive income | 118 | 553 | 411 | 579 |
| Net earnings per common share, basic | 0.22 | 1.07 | 0.79 | 1.13 |
| Net earnings per common share, diluted | 0.22 | 1.07 | 0.79 | 1.13 |
| Common stock price per share: | | | | |
| High | 69.20 | 71.56 | 69.22 | 67.86 |
| Low | 44.45 | 65.04 | 65.33 | 60.07 |
| **UTILITY** | | | | |
| Operating revenues [1] | $ 4,101 | $ 4,516 | $ 4,250 | $ 4,271 |
| Operating income | 434 | 834 | 749 | 883 |
| Income tax provision [2] | 33 | 138 | 136 | 120 |
| Net income [3] | 200 | 513 | 409 | 569 |
| Income available for common stock | 196 | 510 | 405 | 566 |
| Comprehensive income | 203 | 513 | 409 | 570 |
| | | | | |
| **2016** | | | | |
| **PG&E CORPORATION** | | | | |
| Operating revenues [4] | $ 4,713 | $ 4,810 | $ 4,169 | $ 3,974 |
| Operating income | 1,041 | 640 | 401 | 95 |
| Income tax (benefit) provision [5] | 160 | 70 | 12 | (187) |
| Net income [6] | 696 | 391 | 210 | 110 |
| Income available for common shareholders | 692 | 388 | 206 | 107 |
| Comprehensive income | 694 | 391 | 210 | 110 |
| Net earnings per common share, basic | 1.37 | 0.77 | 0.41 | 0.22 |
| Net earnings per common share, diluted | 1.36 | 0.77 | 0.41 | 0.22 |
| Common stock price per share: | | | | |
| High | 62.12 | 65.39 | 63.92 | 59.72 |
| Low | 58.04 | 60.82 | 56.62 | 51.29 |
| **UTILITY** | | | | |
| Operating revenues [4] | $ 4,714 | $ 4,809 | $ 4,169 | $ 3,975 |
| Operating income | 1,044 | 640 | 401 | 96 |
| Income tax (benefit) provision [5] | 169 | 73 | 13 | (185) |
| Net income [6] | 696 | 389 | 209 | 108 |
| Income available for common stock | 692 | 386 | 205 | 105 |
| Comprehensive income | 694 | 389 | 210 | 108 |

[1] In the first quarter of 2017, the Utility recorded the remaining retroactive revenues related to the 2015 GT&S rate case decision authorized by the CPUC.
[2] In the fourth quarter of 2017, the Utility had lower income tax expense primarily due to lower o perating income, which was partially offset by the impact of the Tax Act.

[3] In the second quarter of 2017, the Utility recorded a $47 million disallowance related to the Diablo Canyon settlement. Also, in the third quarter of 2017, the Utility recorded a $350 million charge related to Butte fire third-party claims. In the first, second, and third quarters of 2017, the Utility recorded $ 7 million , $14 million, and $276 million, respectively, for probable insurance recoveries in connection with recovery of losses related to the Butte fire . (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

[4] In the third and fourth quarters of 2016, the Utility recorded an increase in base revenues as authorized by the CPUC in the 2015 GT&S rate case decision.

[5] In the first quarter of 201 6, the Utility had an income tax benefit, primarily due to net loss before income taxes and various tax audit results.

[6] In the first, second, and third quarters of 2016, the Utility recorded charges fo r disallowed capital spending of $87 million, $148 million, and $51 million, respectively, as a result of the San Bruno Penalty Decision. Additionally, in the second and fourth quarters of 2016, the Utility recorded charges of $190 million and $29 million for capital expenditures probable of disallowance related to the final decision in the 2015 GT&S rate case. Also, in the first quarter of 2016 the Utility recorded a $350 million charge related to Butte fire litigation. In the second quarter of 2016, th e Utility recorded $260 million for probable insurance recoveries in connection with recovery of losses related to the Butte fire . In the fourth quarter of 2016, the Utility recorded a $400 million charge related to the Butte fire litigation and an insura nce receivable of $365 million for probable insurance recoveries in connection with the Butte fire. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

## MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

Management of PG&E Corporation and the Utility is responsible for establishing and maintaining adequate internal control over financial reporting. PG&E Corporation's and the Utility's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles, or GAAP. Internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of PG&E Corporation and the Utility, (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP and that receipts and expenditures are being made only in accordance with authorizations of management and directors of PG&E Corporation and the Utility, and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of internal control over financial reporting as of December 31, 2017 , based on the criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on its assessment and those criteria, management has concluded that PG&E Corporation and the Utility maintained effective internal control over financial reporting as of December 31, 2017 .

Deloitte & Touche LLP, an independent registered public accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2017 , based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Shareholders and the Board of Directors of
PG&E Corporation

**Opinion on Internal Control over Financial Reporting**

We have audited the internal control over financial reporting of PG& E Corporation and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accor dance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Company and our report dated February 9, 2018, expressed an unqu alified opinion on those consolidated financial statements and included an emphasis-of-matter paragraph regarding uncertainty related to possible material losses or penalties to the Company as a result of the Northern California wildfires that occurred in October 2017, as discussed in Note 13 to the consolidated financial statements .

**Basis for Opinion**

The Company's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting* . Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Com mission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was ma intained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal con trol based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

**Definition and Limitations of Internal Control over Financial Reporting**

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with gen erally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions an d dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expen ditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the c ompany's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent, or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 9, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Shareholders and the Board of Directors of
Pacific Gas and Electric Company

**Opinion on Internal Control over Financial Reporting**

We have audited the internal control over financial reporting of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Tr eadway Commission (COSO). In our opinion, the Utility maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements as of and for the year ended December 31, 2017, of the Utility and our repor t dated February 9, 2018, expressed an unqualified opinion on those consolidated financial statements and included an emphasis-of-matter paragraph regarding uncertainty related to possible material losses or penalties to the Utility as a result of the Nor thern California wildfires that occurred in October 2017, as discussed in Note 13 to the consolidated financial statements .

**Basis for Opinion**

The Utility's management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Inter nal Control Over Financial Reporting* . Our responsibility is to express an opinion on the Utility's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Utility in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those s tandards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in t he circumstances. We believe that our audit provides a reasonable basis for our opinion.

**Definition and Limitations of Internal Control over Financial Reporting**

A company's internal control over financial reporting is a process designed to provide reaso nable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes t hose policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are rec orded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and director s of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent, or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in condi tions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 9, 2018

**REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

To the Shareholders and the Board of Directors of
PG&E Corporation

**Opinion on the Financial Statements**

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subs idiaries (the "Company") as of December 31, 2017 and 2016, the Company's related consolidated sta tements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017 , and the related notes and the schedules listed in the Index at Item 15 (collectively referred to as the "financial statement s"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period e nded December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversig ht Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Tr eadway Commission and our report dated February 9, 2018 expressed an unqualified opinion on the Company's internal control over financial reporting.

**Basis for Opinion**

These financial statements are the responsibility of the Company's management. Our resp onsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal secu rities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reaso nable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to erro r or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principle s used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

**Emphasis of Matter**

As discussed in Note 13 to the consolidated financial statements, the Northern California wildfires that occurred in October 2017 may result in material losses or penalties to the Company .

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 9, 2018

We have served as the Company's auditor since 1999.

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of
Pacific Gas and Electric Company

**Opinion on the Financial Statements**

We have audited the accompanying consolidated balance sheets of Pacific Gas and Electric Company and subsidiaries (the "Utility") as of December 31, 2017 and 2016, and the Utility's related consolidated statements of income, co mprehensive income, shareholders' equity, and cash flows, for each of the three years in the period ended December 31, 2017 , and the related notes and the schedule listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Utility as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended Dec ember 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Boa rd (United States) (PCAOB), the Utility's in ternal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control — Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 9, 2018 expressed an unqualified opinion on the Utility's internal control over financial reporting.

**Basis for Opinion**

These financial statements are the responsibility of the Utility's management. Our responsibility is to express an opinion on the Utility 's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Utility in accordance with the U.S. federal securities laws and the applicable rules and regulatio ns of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statem ents are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by managemen t, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

**Emphasis of Matter**

As discussed in Note 13 to the consolidated financial statements, the Northern Califo rnia wildfires that occurred in October 2017 may result in material losses or penalties to the Utility .

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 9, 2018

We have served as the Utility's auditor since 1999.

## ITEM 9 . CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

Not applicable.

## ITEM 9A. CONTROLS AND PROCEDURES

### Evaluation of Disclosure Controls and Procedures

Based on an evaluation of PG&E Corporation's and the Utility's disclosure controls and procedures as of December 31, 2017 , 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 1934 Act 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 C orporation'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.

### Management's Annual Report on Internal Control over Financial Reporting

Management of PG&E Corporation and the Util ity have prepared an annual report on internal control over financial reporting. Management's report, together with the report of the independent registered public accounting firm, appears in Item 8 of this 2017 Form 10-K under the heading "Management's R eport on Internal Control Over Financial Reporting" and "Report of Independent Registered Public Accounting Firm."

### Registered Public Accounting Firm's Report on Internal Control over Financial Reporting

Deloitte & Touche LLP, an independent registered pu blic accounting firm, has audited PG&E Corporation's and the Utility's internal control over financial reporting as of December 31, 2017 , based on criteria established in *Internal Control — Integrated Framew ork (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

### Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting that occurred during the quarter ended Dece mber 31, 2017 that have materially affected, or are reasonably likely to materially affect, PG&E Corporation's or the Utility's internal control over financial reporting.

## ITE M 9B. OTHER INFORMATION

Not applicable.

# PART III

## ITEM 10 . DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Information regarding executive officers of PG&E Corporation and the Utility is set forth under "Executive Officers of the Registrants" a t the end of Part I of this 2017 Form 10-K. Other information regarding directors will be included under the heading "Nominees for Directors of PG&E Corporation and Pacific Gas and Electric Company" in the Joint Prox y Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference. Information regarding compliance with Section 16 of the Exchange Act will be included under the heading "Section 16(a) Beneficial Ownership Reporting Compliance" in the Joint Prox y Statement relating to the 2018 Annual Meetings of Shareholders, which infor mation is incorporated herein by reference.

***Website Availability of Code of Ethics, Corporate Governance and Other Documents***

The following documents are available both on the Corporate Governance section of PG&E Corporation's website ( *www.pgecorp.com/corp/about-us/corporate-governance.page* ) and on the Utility's website ( *www.pge.com/en_US/about-pge/company-information/company-information.page* , under the "Visit Corporate Governance" link ): (1) the PG&E Corporation 's and the Utility's code s of conduct (which meet the definition of "code of ethics" of Item 406(b) of the SEC Regulation S-K) adopted by PG&E Corporation and the Utility and applicable to their directors and employees, including their respective Chief Executive Officer and Presid ent , as the case may be, Chief Financial Officers, Controllers and other executive officers, (2) PG&E Corporation's and the Utility's respective corporate governance guidelines, and (3) key Board committee charters, including charters for the companies' Au dit Committees and the PG&E Corporation Nominating and Governance Committee and Compensation Committee.

If any amendments are made to, or any waivers are granted with respect to, provisions of the code of conduct adopted by PG&E Corporation and the Utilit y and that apply to their respective Chief Executive Officer and President , as the case may be, Chief Financial Officers, or Controllers, PG&E Corporation and the Utility will post the amended code of ethics on their websites and will disclose any waivers to the " code of ethics" in a Current Report on Form 8-K.

***Procedures for Shareholder Recommendations of Nominees to the Boards of Directors***

T here were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Stat ement relating to the 2017 Annual Meetings of Shareholders by which security holders may recommend nominees to PG&E Corporation's or Pacific Gas and Electric Company's Boards of Directors.

***Audit Committees and Audit Committee Financial Expert***

Information regarding the Audit Committees of PG&E Corporation and the Utility and the "audit committee financial experts" as defined by the SEC will be included under the headings "Corporate Governance – Board Committ ee Duties – Audit Committees" and "Corporate Governance – Committee Membership , Independence, and Qualifications " in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## ITEM 11 . EXECUTIVE COMPENSATION

Information responding to Item 11, for each of PG&E Corporation and the Utility, will be included under the headings "Compensation Discussion and Analysis," "Compensation Committee Report," "Summary Compensation Table - 2017 ," "Grants of Plan-Based Awards in 201 7 ," "Outstanding Equity Awards at Fiscal Year End - 2017 ," "Option Exercises and Stock Vested During 2017 ," "Pension Benefits – 2017 ," "Non-Qualified Deferred Compensation – 2017 ," "Potential Payments Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of No n-Employee Directors – 2017 Director Compensation" in the Joint Proxy Statement relating to the 2018 Annual Meetings of Sh areholders, which information is incorporated herein by reference.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Information regarding the beneficial ownership of securities for each of PG&E Corpor ation and the Utility is set forth un der th e headings "Share Ownership Information – Security Ownership of Management" and "Share Ownership Information – Principal Shareholders" in the Joint Proxy Statement relating to the 2018 Annual Meetings of Sharehold ers, which information is incorporated herein by reference.

***Equity Compensation Plan Information***

The following table provides information as of December 31, 2017 concerning shares of PG&E Corporation common stock authorized for issuance under PG&E Corpo ration's existing equity compensation plans.

| Plan Category | (a) Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants and Rights | | (b) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights | (c) Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a)) |
|---|---|---|---|---|
| Equity compensation plans approved by shareholders | 4,969,352 (1) | $ | 35.53 (2) | 14,381,959 (3) |
| Equity compensation plans not approved by shareholders | - | | - | - |
| Total equity compensation plans | 4,969,352 (1) | $ | 35.53 (2) | 14,381,959 (3) |

(1) Includes 14,041 phantom stock units, 1,426,37 1 restricted stock units and 3,524 , 850 performance shares. The weighted average exercise price reported in column (b) does not take these awards into account. For performance shares, amounts reflected in this table assume payout in shares at 200% of target or, for performance shares grant ed in 2015, reflects the actual payout percentage of 0% for performance shares using a total shareholder return metric and 15.1%for performance shares using safety and affordability metrics. The actual number of shares issued can range from 0% to 200% of target depending on achievement of performance objectives. Also, restricted stock units and performance shares are generally settled in net shares. Upon vesting, shares with a value equal to required tax withholding will be withheld and, in lieu of issui ng the shares, taxes will be paid on behalf of employees. Shares not issued due to share withholding or performance achievement below maximum will be available again for issuance .

(2) This is the weighted average exercise price for the 4,090 options outst anding as of December 31, 2017.

(3) R epresents the total number of shares available for issuance under all of PG&E Corporation's equity compensation plans as of December 31, 2017. Stock-based awards granted under these plans include restricted stock units, performance shares and phantom stock units. The 2014 LTIP, which became effective on May 12, 2014, authorizes up to 17 million shares to be issued pursuant to awards granted under the 2014 LTIP, less approximately 2.7 million shares for awards granted un der the 2006 LTIP from January 1, 2014 through May 11, 2014. In addition, if any awards outstanding under the 2006 LTIP at December 31, 2013 are cancelled, forfeited or expire without being settled in full, shares of stock allocable to the terminated port ion of such awards shall again be available for issuance under the 2014 LTIP .

F or more information, see Note 5 of the Notes to the Consolidate d Financial Statements in Item 8.

## ITE M 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPEN DENCE

Information responding to Item 13, for each of PG&E Corporation and the Utility, will be included under the headings "Related Party Transactions" and "Corporate Governance – Board and Director General Independence and Qualifications" and "Corporate Governance – Committee Membership, Independence, and Qualifications" in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## ITEM 14 . PRINCIPAL ACCOUNTANT FEES AND SERVICES

Information responding to Item 14, for each of PG&E Corporation and the Utility, will be included under the heading "Information Regarding the Independent Auditor for PG&E Corporation and Pacific Gas and Electric Company" in the Joint Proxy Statement rel ating to the 2018 Annual Meetings of Shareholders, which information is incorporated herein by reference.

## PART IV

## ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

**A. The following documents are filed as a part of this report:**

1. The following consolidated financial statements, supplemental information and report of independent registered public accounting firm are filed as p art of this report in Item 8 :

Consolidated Statements of Income for the Years Ended December 31, 201 7 , 201 6, and 2015 for each of PG& E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Comprehensive Income for the Years Ended December 31, 201 7 , 201 6, and 2015 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Bal ance Sheets at De cember 31, 2017 and 201 6 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 201 7 , 201 6, and 2015 for each of PG&E Corporation and Pacific Gas and Electric Company.

Co nsolidated Statements of Equity for the Years Ended December 31, 201 7 , 201 6, and 2015 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 201 7 , 201 6, and 2015 for Pacific Gas and Electric Company.

Notes to the Consolidated Financial Statements.

Quarterly Consolidated Financial Data (Unaudited).

Management's Report on Internal Controls

Reports of Independent Registered Public Accountin g Firm (Deloitte & Touche LLP).

The following financial statement schedules are filed as part of this report:

Condensed Financial Information of Parent as of December 31, 2017 and 201 6 and for the Years Ended December 31, 201 7 , 201 6, and 2015 .

Consolidated Valuation and Qualifying Accounts for each of PG&E Corporation and Pacific Gas and Electric Company for the Years Ended December 31, 201 7 , 201 6, and 2015 .

3. Exhibits required by Item 601 of Regulation S-K

**EXHIBIT INDEX**

| Exhibit Number | Exhibit Description |
|---|---|
| 3.1 | Restated Articles of Incorporation of PG&E Corporation effective as of May 29, 2002 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12609), Exhibit 3.1) |
| 3.2 | Certificate of Determination for PG&E Corporation Series A Preferred Stock filed December 22, 2000 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2000 (File No. 1-12609), Exhibit 3.2) |
| 3.3 | Bylaws of PG&E Corp oration 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) |
| 3.4 | Restated Articles of Incorporation of Pacific Gas and Electric Company effective as of April 12, 2004 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 12, 2004 (File No. 1-2348), Exhibit 3) |
| 3.5 | Bylaws of Pacific Gas and Electric Company amended as of December 16, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2016 (File No. 1-2348), Exhibit 3.5) |
| 4.1 | Indenture, dated as of April 22, 2005, supplementing, amending and restating the Indenture of Mortgage, dated as of March 11, 2004, as supplemented by a First Supplemental Indenture, dated as of March 23, 2004, and a Second Supplemental Indenture, dated as of April 12, 2004, between Pacific Gas and Electric Company and The Bank of New York Trust C ompany, N.A. (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2005 (File No. 1-2348), Exhibit 4.1) |
| 4.2 | First Supplemental Indenture, dated as of March 13, 2007, relating to the issuance of $700,000,000 principal amount of Pacific Gas and Electric Company's 5.80% Senior Notes due March 1, 2037 (incorporated by reference from Pacific Gas and Electric Company's Form 8-K dated March 14, 2007 (File No. 1-2348), Exhibit 4.1) |
| 4.3 | Third Supplemental Indenture, dated as of March 3, 2008, relating to the issuance of $400,000,000 of Pacific Gas and Electric Company's 6.35% Senior Notes due February 15, 2038 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated Marc h 3, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.4 | Fourth Supplemental Indenture, dated as of October 21, 2008, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 8.25% Senior Notes due October 15, 201 8 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated October 21, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.5 | Fifth Supplemental Indenture, dated as of November 18, 2008, relating to the issuance of $200,000,000 principal amount of Pacific Gas and Electric Company's 8.25% Senior Notes due October 15, 2018 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2008 (File No. 1-2348), Exhibit 4.1) |
| 4.6 | Sixth Supplemental Indenture, dated as of March 6, 2009, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 6.25% Senior Notes due March 1, 2039 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 6, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.7 | Seventh Supplemental Indenture, dated as of June 11, 2009, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due June 10, 2010 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 11, 2009 (File No. 1-2348), Exhibit 4.1) |

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| 4.8 | Eighth Supplemental Indenture, dated as of November 18, 2009, relating to the issuance of $550,000,000 aggregate principa l amount of Pacific Gas and Electric Company's 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 18, 2009 (File No. 1-2348), Exhibit 4.1) |
| 4.9 | Ninth Supplemental Indenture, dated as of April 1, 2010, relating to the issuance of $250,000,000 aggregate principal amount of its 5.80% Senior Notes due March 1, 2037 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 1 , 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.10 | Tenth Supplemental Indenture, dated as of September 15, 2010, relating to the issuance of $550,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 15, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.11 | Twelfth Supplemental Indenture, dated as of November 18, 2010, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due October 1, 2020 and $250,000,000 aggregate principal amount of its 5.40% Senior Notes due January 15, 2040 (incorporated by reference to Pacific Gas and Electric Company's Form 8 -K dated November 18, 2010 (File No. 1-2348), Exhibit 4.1) |
| 4.12 | Thirteenth Supplemental Indenture, dated as of May 13, 2011, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.25% Senior Notes due May 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated May 13, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.13 | Fourteenth Supplemental Indenture, dated as of September 12, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.25% Senior Notes due September 15, 2021 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated September 12, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4 .14 | Sixteenth Supplemental Indenture, dated as of December 1, 2011, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.50% Senior Notes due December 15, 2041 (incorporated by reference to Pacific Ga s and Electric Company's Form 8-K dated December 1, 2011 (File No. 1-2348), Exhibit 4.1) |
| 4.15 | Seventeenth Supplemental Indenture, dated as of April 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electr ic Company's 4.45% Senior Notes due April 15, 2042 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated April 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.16 | Eighteenth Supplemental Indenture, dated as of August 16, 2012, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.45% Senior Notes due August 15, 2022 and $350,000,000 aggregate principal amount of its 3.75% Senior Notes due August 15, 2042 (incorporated by refe rence to Pacific Gas and Electric Company's Form 8-K dated August 16, 2012 (File No. 1-2348), Exhibit 4.1) |
| 4.17 | Nineteenth Supplemental Indenture, dated as of June 14, 2013, relating to the issuance of $375,000,000 aggregate principal amount of Pacifi c Gas and Electric Company's 3.25% Senior Notes due June 15, 2023 and $375,000,000 aggregate principal amount of its 4.60% Senior Notes due June 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 14, 2013 (File No . 1-2348), Exhibit 4.1) |
| 4.18 | Twentieth Supplemental Indenture, dated as of November 12, 2013, relating to the issuance of $300,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.85% Senior Notes due November 15, 2023 and $500,000,000 aggregate principal amount of its 5.125% Senior Notes due November 15, 2043 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 12, 2013 (File No. 1-2348), Exhibit 4.1) |

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| 4.19 | Twenty-First Supplemental Indenture, dated as of February 21, 2014, relating to the issuance of $450,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.75% Senior Notes due February 15, 2024 and $450,000,000 aggregate principal amount of its 4.75% Senior Not es due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated February 21, 2014 (File No.1 2348), Exhibit 4.1) |
| 4.20 | Twenty-Third Supplemental Indenture, dated as of August 18, 2014, relating to the issuance of $350,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.40% Senior Notes due August 15, 2024 and $225,000,000 aggregate principal amount of its 4.75% Senior Notes due February 15, 2044 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated August 18, 2014 (File No. 1 - 2348), Exhibit 4.1) |
| 4.2 1 | Twenty-Fourth Supplemental Indenture, dated as of November 6, 2014, relating to the issuance of $500,000,000 aggregate principal amount of Pacific Gas and Electric Company's 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated November 6, 2014 (File No. 1 - 234 8), Exhibit 4.1) |
| 4.22 | Twenty-Fifth Supplemental Indenture, dated as of June 12, 2015, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $100,000,000 aggregate principal amount of its 4.30% Senior Notes due March 15, 2045 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated June 12, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.23 | Twenty-Sixth Supplemental Indenture, dated as of November 5, 2015, relating to the issuance of $200,000,000 aggregate principal amount of Pacific Gas and Electric Company's 3.50% Senior Notes due June 15, 2025 and $450,000,000 aggregate principal amount of its 4.25% Senior Notes due March 15, 2046 (incor porated by reference to Pacific Gas and Electric Company's Form 8-K dated November 5, 2015 (File No. 1-2348), Exhibit 4.1) |
| 4.24 | Twenty-Seventh Supplemental Indenture, dated as of March 1, 2016, relating to the issuance of $600,000,000 aggregate principal amount of Pacific Gas and Electric Company's 2.95% Senior Notes due March 1, 2026 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 1, 2016 (File No. 1-2348), Exhibit 4.1 ) |
| 4.25 | Twenty-Eighth Supplemental Indenture, dated as of December 1, 2016, relating to the issuance of $250,000,000 aggregate principal amount of Pacific Gas and Electric Company's Floating Rate Senior Notes due November 30, 2017 and $400,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated December 1, 2016 (File No. 1-2348), Exhibit 4.1) |
| 4.26 | Twenty-Ninth Supplemental Indenture, dated as of March 10, 2017, relating to the issuance of $400,000,000 aggregate principal amount of Pacific Gas and Electric Company 's 3.30% Senior Notes due March 15, 2027 and $200,000,000 aggregate principal amount of its 4.00% Senior Notes due December 1, 2046 (i ncorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 10, 2017 (File No. 1-2348), Exhibit 4.1) |
| 4.27 | Indenture, dated as of November 29, 2017, relating to the issuance of $500,000,000 aggregate principal amount of by Pacific Gas and Electric Company 's Floating Rate Senior Notes due 2018, $1,150,000,000 aggregate principal amount of its 3.30% Senior Notes due 2027 and $850,000,000 aggregate principal amount of its 3.95% Senior Notes due 2047 (incorporated by reference to Pacifi c Gas and Electric Company's Form 8-K dated November 29, 2017 (File No. 1-2348), Exhibit 4.1) |
| 4.28 | Senior Note Indenture, dated as of February 10, 2014, between PG&E Corporation and U.S. Bank National Association (incorporated by reference to PG&E Corporation's Form S-3 (File No. 333-193880), Exhibit 4.1) |
| 4.29 | First Supplemental Indenture, dated as of February 27, 2014, relating to the issuance of $350,000,000 aggregate principal amount of PG&E Corporation's 2.40% Senior Notes due March 1, 2019 (incorporated by reference to PG&E Corporation's Form 8-K dated February 27, 2014 (File No. 1-12609), Exhibit 4.1) |

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|---|---|---|
| 4.30 | | Registration Rights Agreement, dated as of November 29, 2017, among Pacific Gas and Electric Company and Barclays Capital Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC, as representatives of the initial purchasers (incorporated by reference to Pacific Gas and Electric Company 's Form 8-K dated November 29, 2017 (File No. 1-2348 ), Exhibit 4. 5 ) |
| 10.1 | | Second Amended and R estated C redit A greement , dated as of April 27, 2015, among (1) PG&E Corporation , as borrower, (2) Bank of America, N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securities LLC, and Wells Fargo Securities LLC , as joint lead arrangers and jo int bookrunners, (4) Citibank N.A. and JPMorgan Chase Bank, N.A., as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association , as documentation agent and lender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Gold man Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. Bank , National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperi al Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.2 | | Second Amended and R estated C redit A greement dated as of April 27, 2015, among (1) Pacific Gas and Electric Company , as borrower, (2) Citibank N.A., as administrative agent and a lender, (3) Merrill Lynch, Pierce, Fenner & Smith Incorporated, Citigroup Global Markets Inc., J.P. Morgan Securi ties LLC, and Wells Fargo Securities LLC , as joint lead arrangers and joint bookrunners, (4) Bank of America, N.A. and JPMorgan Chase Bank, N.A. , as co-syndication agents and lenders, (5) Wells Fargo Bank, National Association , as documentation agent and l ender, and (6) the following other lenders: Barclays Bank PLC, BNP Paribas, Goldman Sachs Bank USA, Morgan Stanley Bank, N.A., Morgan Stanley Senior Funding, Inc., The Bank of New York Mellon, N.A., Mizuho Corporate Bank, Ltd., Royal Bank of Canada, U.S. B ank National Association, MUFG Union Bank, N.A., TD Bank, N.A., Canadian Imperial Bank of Commerce, New York Branch, and Sumitomo Mitsui Banking Corporation (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended Ma rch 31, 2015 (File No. 1-2348), Exhibit 10.2) |
| 10.3 | | Term Loan Agreement, dated as of March 2, 2016, between Pacific Gas and Electric Company and The Bank of Tokyo-Mitsubishi UFJ, Ltd. (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated March 2, 2016 (File No. 1-2348), Exhibit 10.1) |
| 10.4 | | Term Loan Agreement, dated as of February 23, 2017, 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 Comp any's Form 8-K dated February 23, 2017 (File No. 1-2348), Exhibit 10.1) |
| 10.5 | | Purchase Agreement, dated as of November 27, 2017, among Pacific Gas and Electric Company and Barclays Capital Inc., Citigroup Global Markets Inc., J.P. Morgan Securities LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated and Morgan Stanley & Co. LLC, as representatives of the initial purchasers listed on Schedules I-A, I-B and I-C thereto (incorporated by reference to Pacific Gas and Electric Company's Form 8-K dated Nove mber 29, 2017 (File No. 1-2348), Exhibit 10.1) |
| 10.6 | | Settlement Agreement among the California Public Utilities Commission, Pacific Gas and Electric Company and PG& E Corporation, dated as of December 19, 2003, together with appendices (incorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 8-K dated December 22, 2003 (File No. 1-12609 and File No. 1-2348), Exhibit 99) |
| 10.7 | | Transmission Control Agreement among the California Independent System Operator (CAISO) and the Participating Transmission Owners, including Pacific Gas and Electric Company, effective as of March 31, 1998, as amended (CAISO, FERC Electric Tariff No. 7) (i ncorporated by reference to PG&E Corporation's and Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-12609 and File No. 1-2348), Exhibit 10.8) |
| 10.8 | * | Letter regarding Compensation Agreement between PG&E Corporation and Anthony F. Earley, Jr. dated August 8, 2011 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2011 (File No. 1-12609), Exhibit 10.1) |

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|---|---|---|
| 10.9 | * | Restricted Stock Unit Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2017 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference t o PG&E Corporation's Form 10- Q for the quarter ended June 30 , 201 7 (File No. 1-12609), Exhibit 10. 04) |
| 10.10 | * | Restricted S tock Unit Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-1260 9), Exhibit 10.7) |
| 10.11 | * | Restricted Stock Unit Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.7 ) |
| 10.12 | * | Restricted Stock Unit Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2014 grant under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.4 ) |
| 10.13 | * | Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation for 2013 grant under the PG&E C orporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.5) |
| 10.14 | * | Performance Share Agreement subject to financial goals between Anthony F. Ea rley, Jr. and PG&E Corporation for 2017 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference t o PG&E Corporation's Form 10- Q for the quarter ended June 30 , 201 7 (File No. 1-12609), Exhibit 10. 05) |
| 10.15 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.12) |
| 10.16 | * | Performance Share Agreement subject to financial goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.8 ) |
| 10.17 | * | Performance Share Agreement subject to safety and custom er affordability goals between Anthony F. Earley, Jr. and PG&E Corporatio n for 2017 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.06) |
| 10.18 | * | Performance Share Agreement subject to safety and custom er affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2016 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.14) |
| 10.19 | * | Performance Share Agreement subject to safety and custom er affordability goals between Anthony F. Earley, Jr. and PG&E Corporation for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (inc orporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2015 (File No. 1-12609), Exhibit 10.9 ) |
| 10.20 | * | Performance Share Agreement between Anthony F. Earley, J r. and PG&E Corporation for 2014 grant under the PG&E Corporati on 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.5 ) |
| 10.21 | * | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2015 (File No. 1-2609), Exhibit 10.16) |
| 10.22 | * | Restricted Stock Unit Agreement between Nickolas Stavropoulos and PG&E Corporation for non-annual award under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.0 8) |

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| 10.23 | * | Restricted Stock Unit Agreement between Geisha J. Williams and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2015 (File No. 1-2609), Exhibit 10.17) |
| 10.24 | * | Restricted Stock Unit Agreement between John R. Simon and PG&E Corporation for additional 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2015 (File No. 1-2609), Exhibit 10.18) |
| 10.25 | * | Letter regarding Compensation Agreement between PG&E Corporation and Julie M. Kane dated March 11, 2015 for employment starting May 18, 2015 (incorporat ed by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.4) |
| 10.26 | * | Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.5) |
| 10.27 | * | Non-Annual Restricted Stock Unit Agreement between Julie M. Kane and PG&E Corporation dated May 29, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.6) |
| 10.28 | * | Performance Share Agreement subject to financial goals between Julie M. Kane and PG&E Co rporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.7) |
| 10.29 | * | Performance Share Agreement subject to safety and customer affordability goals between Julie M. Kane and PG&E Corporation dated May 29, 2015 for 2015 grant under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q fo r the quarter ended June 30, 2015 (File No. 1-2348), Exhibit 10.8) |
| 10.30 | * | Restricted Stock Unit Agreement between Dinyar Mistry and PG&E Corporation dated February 23, 2016 (incorporated by reference to PG&E Corporation and Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-12609 and File No. 1-2348), Exhibit 10.2) |
| 10.31 | * | Separation Agreement between PG&E Corporation and Hyun Park dated August 7, 2017 and amended as of September 1, 2017 (incorporated by reference t o PG&E Corporation's Form 10- Q for the quarter ended September 30 , 201 7 (File No. 1-12609), Exhibit 10. 1) |
| 10.32 | * | Separation Agreement between Pacific Gas and Electric Company and Desmond Bell dated January 6, 2017 and amended as of April 25, 2017 (incorporated by reference t o Pacific Gas and Electric Company 's Form 10- Q for the quarter ended June 30 , 201 7 (File No. 1- 2348 ), Exhibit 10. 09) |
| 10.33 | * | Separation Agreement between Pacific Gas and Electric Company and Helen Burt dated January 5, 2017 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2017 (File No. 1-2348), Exhibit 10.3) |
| 10.34 | * | Letter regarding Compensation Agreement between Pacific Gas and Electric Company and David Thomason dated May 24, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-2348), Exhibit 10.2) |
| 10.35 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and David S. Thomason dated August 8, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-2348), Exhibit 10.1) |
| 10.36 | * | Performance Share Award Agreement subject to financial goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609), Exhibit 10.2) |

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| 10.37 | * | Performance Share Award Agreement subject to safety and customer affordability goals between David S. Thomason and PG&E Corporation dated August 8, 2016 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2016 (File No. 1-12609), Exhibit 10.3) |
| 10 .38 | * | Non-Annual Restricted Stock Unit Award Agreement between PG&E Corporation and Edward D. Halpin dated November 28, 2016 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 10.32) |
| 10.39 | * | PG&E Corporation Supplemental Retirement Savings Plan amended effective as of September 19, 2001, and frozen after December 31, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004) (File No. 1-12609 ), Exhibit 10.10) |
| 10.40 | * | PG&E Corporation 2005 Supplemental Retirement Savings Plan, as amended effective September 15, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.3) |
| 10.41 | * | PG&E Corporation 2005 Deferred Compensation Plan for Non-Employee Directors, effective as of January 1, 2005 (as amended to comply with Internal Revenue Code Section 409A regulations effective as of January 1, 2009) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.24) |
| 10.42 | * | PG&E Corporation Deferred Compensation Plan for Non-Employee Directors, as amended and restated effective as of July 22, 1998 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 1998 (File No. 1-12609), Exhibit 10.2) |
| 10.43 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2017 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2017 (File No. 1-12609), Exhibit 10.2) |
| 10.44 | * | Description of Short-Term Incentive Plan for Officers of PG&E Corporation and its subsidiaries, effective January 1, 2016 (incorporated by reference to PG&E Corporation's Form 8-K dated February 16, 2016 (File No. 1-12609) |
| 10.45 | * | Amendment to PG&E Corporation Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comp ly with Internal Revenue Code Section 409A regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.27) |
| 10.46 | * | Amendment to Pacific Gas and Electric Company Short-Term Incentive Programs and Other Bonus Programs, effective January 1, 2009 (amendment to comply with Internal Revenue Code Section 409A regulations) (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2008 (File No. 1-2348), Exhibit 10.28) |
| 10.47 | * | PG&E Corporation Supplemental Executive Retirement Plan, as amended effective as of January 1, 2013 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609, Exhibit 10.31) |
| 10.48 | * | PG&E Corporation Defined Contribution Executive Supplemental Retirement Plan, as amended effective September 17, 2013 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2013 (File No. 1-12609), Exhibit 10.2) |
| 10.49 | * | Pacific Gas and Electric Company Relocation Assistance Program for Officers (incorporated by reference to Pacific Gas and Electric Company's Form 10-K for the year ended Dece mber 31, 2015 (File No. 1-2348), Exhibit 10.38) |
| 10.50 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 16, 2016 (incorporated by reference to Pacific Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2016 (File No. 1-2348), Exhibit 10.4) |

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| 10.51 | * | Amendment to the Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, effective February 6 , 2015 (incorporated by reference to Pacific Gas and Electric Company 's Form 10-K for the year ended December 31, 2014) ( File No. 1-2348 ), Exhibit 10. 37 ) |
| 10.52 | * | Postretirement Life Insurance Plan of the Pacific Gas and Electric Company, as amended and restated on February 14, 2012 (incorporated by reference to Paci fic Gas and Electric Company's Form 10-Q for the quarter ended March 31, 2012 (File No. 1-2348), Exhibit 10.7) |
| 10.53 | * | PG&E Corporation Non-Employee Director Stock Incentive Plan (a component of the PG&E Corporation Long-Term Incentive Program) as amended effective as of July 1, 2004 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.27) |
| 10.54 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2018 |
| 10.55 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective February 15, 2017 |
| 10.56 | * | PG&E Corporation 2014 Long-Term Incentive Plan effective May 12, 2014 and amended effective January 1, 2016 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2015 (File No. 1-12609), Exhibit 10.42) |
| 10.57 | * | PG&E Corporation 2006 Long-Term Incentive Plan, as amended effective January 1, 2013 (incorporated by refere nce to PG&E Corporation's Form 10-K for the year ended December 31, 2012 (File No. 1-12609), Exhibit 10.40) |
| 10.58 | * | PG&E Corporation Long-Term Incentive Program (including the PG&E Corporation Stock Option Plan and Performance Unit Plan), as amended May 16, 2001, (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2001 (File No. 1-12609), Exhibit 10) |
| 10.59 | * | Form of Restricted Stock Unit Agreement for 2017 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.07) |
| 10.60 | * | Form of Restricted Stock Unit Agreement for 2016 grants to non-employee directors under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2016 (File No. 1-12609), Exhibit 10.1) |
| 10.61 | * | Form of Restricted Stock Unit Agreement for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference t o PG&E Corporation's Form 10-Q for the quarter ended June 30 , 201 7 (File No. 1-12609), Exhibit 10. 01) |
| 10.62 | * | Form of Restrict ed Stock Unit Agreement for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference t o PG&E Corpora tion's Form 10-K for the year ended December 31, 201 6 (File No. 1-12609), Exhibit 10. 55 ) |
| 10.63 | * | Form of Restricted Stock Unit Agreement for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 201 5 (File No. 1-12609), Exhibit 10. 4 ) |
| 10.64 | * | Form of Restrict ed Stock Unit Agreement for 2014 grants under the PG&E Cor poration 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Ex hibit 10.2 ) |
| 10.65 | * | Form of Restricted Stock Unit Agreement for 2013 grants under the PG&E Corpor ation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 2013 (File No. 1-12609), Exhibit 10.3) |
| 10.66 | * | Form of Non-Qualified Stock Option Agreement under the PG&E Corporation Long-Term Incentive Program (incorporated by reference to PG&E Corporation's Form 8-K dated January 6, 2005 (File No. 1-12609), Exhibit 99.1) |

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| 10.67 | * | Form of Performance Share Agreement subject to financial goals for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference t o PG&E Corporation's Form 10- Q for the quarter ended June 30 , 201 7 (File No. 1-12609), Exhibit 10. 02) |
| 10.68 | * | Form of Performance Share Agreement sub ject to financial goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference t o PG&E Corpora tion's Form 10-K for the year ended December 31, 201 6 (File No. 1-12609), Exhibit 10. 61 ) |
| 10.69 | * | Form of Performance Share Agreement subject to financial goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 201 5 (File No. 1-12609), Exhibit 10. 5 ) |
| 10.70 | * | Form of Performance Share Ag reement subject to safety and custo mer affordability goals for 2017 grants under the PG&E Corporation 2014 Long-Term Incentive Plan ( incorporated by reference t o PG&E Corporation's Form 10- Q for the quarter ended June 30 , 201 7 (File No. 1-12609), Exhibit 1 0. 03) |
| 10.71 | * | Form of Performance Share Agreement subject to safety and custo mer affordability goals for 2016 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference t o PG&E Corpora tion's Form 10-K for the year ended De cember 31, 201 6 (File No. 1-12609), Exhibit 10. 63) |
| 10.72 | * | Form of Performance Share Agreement subject to safety and customer affordability goals for 2015 grants under the PG&E Corporation 2014 Long-Term Incentive Plan (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended March 31, 201 5 (File No. 1-12609), Exhibit 10. 6 ) |
| 10.73 | * | Form of Perf ormance Share Agreement for 2014 grants under the PG&E Corporation 2006 Long-Term Incentive Plan (incorporated by reference to PG&E Corpora tion's Form 10-Q for the quarter ended March 31, 2014 (File No. 1-12609), Exhibit 10.3 ) |
| 10.74 | * | PG&E Corporation 2010 Executive Stock Ownership Guidelines as adopted September 14, 2010, effective January 1, 2011 (incorporated by reference to PG&E Corporat ion's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.3) |
| 10.75 | * | PG&E Corporation Executive Stock Ownership Program Guidelines as amended effective September 15, 2010 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2010 (File No. 1-12609), Exhibit 10.2) |
| 10.76 | * | PG&E Corporation 2012 Officer Severance Policy, as amended effective as of May 12, 2014 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2014 (File No. 1-12609), Exhibit 10.2) |
| 10.77 | * | PG&E Corporation Golden Parachute Restriction Policy effective as of February 15, 2006 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2005 (File No. 1-12609), Exhibit 10.49) |
| 10.78 | * | Amendment to PG&E Corporation Golden Parachute Restriction Policy dated December 31, 2008 (amendment to comply with Internal Revenue Code Section 409A Regulations) (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2008 (File No. 1-12609), Exhibit 10.58) |
| 10.79 | * | Amended and Restated PG&E Corporation Director Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 (File No. 1-12609), Exhibit 10.1) |
| 10.80 | * | Amended and Restated PG&E Corporation Officer Grantor Trust Agreement dated October 1, 2015 (incorporated by reference to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2015 ( File No. 1-12609), Exhibit 10. 2 ) |
| 10.81 | * | PG&E Corporation and Pacific Gas and Electric Company Executive Incentive Compensation Recoupment Policy effective as of February 17, 2010 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2009 (File No. 1-12609), Exhibit 10.54) |
| 10.82 | * | Resolution of the Board of Directors of PG&E Corporation regarding indemnification of officers and directors dated December 18, 1996 (incorporated by reference to PG&E Corporation's Form 10-K for the year ended December 31, 2004 (File No. 1-12609), Exhibit 10.40) |
| 10.83 | * | Resolution of the Board of Directors of Pacific Gas and Electric Company regarding indemnification of officers and directors dated July 19, 1995 (incorporated by referenc e to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41) |

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| 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 |
| 21 | | Subsidiaries of the Registrant |
| 23.1 | | PG&E Corporation Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 23.2 | | Pacific Gas and Electric Company Consent of Independent Registered Public Accounting Firm (Deloitte & Touche LLP) |
| 24 | | Powers of Attorney |
| 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 |

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| * | 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. |

## ITEM 16. FORM 10-K SUMMARY

None.

**SIGNATURES**

**Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrants have duly caused this Annual Report on Form 10-K for the year ended December 31, 2017 to be signed on their behalf by the undersigned, thereunto duly authorized.**

| PG&E CORPORATION (Registrant) | | PACIFIC GAS AND ELECTRIC COMPANY (Registrant) | |
|---|---|---|---|
| | GEISHA J. WILLIAMS<br>Geisha J. Williams | | NICKOLAS STAVROPOULOS<br>Nickolas Stavropoulos |
| By: | Chief Executive Officer and President | By: | President and Chief Operating Officer |
| Date: | February 9, 2018 | Date: | February 9, 2018 |

**Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrants and in the capacities and on the dates indicated.**

| Signature | Title | Date |
|---|---|---|
| **A. Principal Executive Officers** | | |
| GEISHA J. WILLIAMS<br>Geisha J. Williams | Chief Executive Officer and President (PG&E Corporation) | February 9, 2018 |
| NICKOLAS STAVROPOULOS<br>Nickolas Stavropoulos | President and Chief Operating Officer (Pacific Gas and Electric Company) | February 9, 2018 |
| **B. Principal Financial Officers** | | |
| JASON P. WELLS<br>Jason P. Wells | Senior Vice President and Chief Financial Officer (PG&E Corporation) | February 9, 2018 |
| DAVID S. THOMASON<br>David S. Thomason | Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 9, 2018 |
| **C. Principal Accounting Officer** | | |
| DAVID S. THOMASON<br>David S. Thomason | Vice President and Controller (PG&E Corporation)<br>Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company) | February 9, 2018 |
| **D. Directors (PG& E Corporation and Pacific Gas and Electric Company, unless otherwise noted)** | | |
| * LEWIS CHEW<br>Lewis Chew | Director | February 9, 2018 |

| | | |
|---|---|---|
| * FRED J. FOWLER<br>Fred J. Fowler | Director | February 9, 2018 |
| * JEH C. JOHNSON<br>Jeh C. Johnson | Director (PG&E Corporation only) | February 9, 2018 |
| * RICHARD C. KELLY<br>Richard C. Kelly | Director<br>Chair of the Board (PG&E Corporation) | February 9, 2018 |
| * ROGER H. KIMMEL<br>Roger H. Kimmel | Director | February 9, 2018 |
| * RICHARD A. MESERVE<br>Richard A. Meserve | Director | February 9, 2018 |
| * FORREST E. MILLER<br>Forrest E. Miller | Director<br>Chair of the Board (Pacific Gas and Electric Company) | February 9, 2018 |
| * ERIC D. MULLINS<br>Eric D. Mullins | Director | February 9, 2018 |
| * ROSENDO G. PARRA<br>Rosendo G. Parra | Director | February 9, 2018 |
| * BARBARA L. RAMBO<br>Barbara L. Rambo | Director | February 9, 2018 |
| * ANNE SHEN SMITH<br>Anne Shen Smith | Director | February 9, 2018 |
| * NICKOLAS STAVROPOULOS<br>Nickolas Stavropoulos | Director (Pacific Gas and Electric Company only) | February 9, 2018 |
| * GEISHA J.WILLIAMS<br>Geisha J. Williams | Director | February 9, 2018 |
| *By:<br>John R. Simon, Attorney-in-Fact | | February 9, 2018 |

**PG&E CORPORATION**
**SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT**
**CONDENSED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME**

| | Years Ended December 31, | | |
|---|---|---|---|
| **(in millions, except per share amounts)** | **2017** | **2016** | **2015** |
| Administrative service revenue | $ 63 | $ 70 | $ 51 |
| Operating expenses | (5) | (73) | (53) |
| Interest income | 1 | 1 | 1 |
| Interest expense | (11) | (10) | (10) |
| Other income | 4 | 2 | 30 |
| Equity in earnings of subsidiaries | 1,667 | 1,388 | 852 |
| Income before income taxes | 1,719 | 1,378 | 871 |
| Income tax provision (benefit) | 73 | (15) | (3) |
| **Net income** | **$ 1,646** | **$ 1,393** | **$ 874** |
| Other Comprehensive Income | | | |
| Pension and other postretirement benefit plans obligations (net of taxes of $0, $1, and $0, at respective dates) | $ 1 | $ (2) | $ (1) |
| Net change in investments (net of taxes of $0, $0, and $12, at respective dates) | - | - | (17) |
| Total other comprehensive income (loss) | 1 | (2) | (18) |
| **Comp rehensive Income** | **$ 1,647** | **$ 1,391** | **$ 856** |
| **Weighted Average Common Shares Outstanding, Basic** | **512** | **499** | **484** |
| **Weig hted Average Common Shares Outstanding, Diluted** | **513** | **501** | **487** |
| **Net earnings per common share, basic** | **$ 3.21** | **$ 2.79** | **$ 1.81** |
| **Net earnings per common share, diluted** | **$ 3.21** | **$ 2.78** | **$ 1.79** |

## PG&E CORPORATION
## SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)
## CONDENSED BALANCE SHEETS

| | Balance at December 31, | |
|---|---|---|
| **(in millions)** | **2017** | **2016** |
| **ASSETS** | | |
| **Current Assets** | | |
| Cash and cash equivalents | $ 2 | $ 106 |
| Advances to affiliates | 24 | 24 |
| Income taxes receivable | 27 | 25 |
| **Total current assets** | **53** | **155** |
| **Noncurrent Assets** | | |
| Equipment | 3 | 2 |
| Accumulated depreciation | (3) | (2) |
| **Net equipment** | **-** | **-** |
| Investments in subsidiaries | 19,514 | 18,172 |
| Other investments | 144 | 133 |
| Intercompany receivable | 72 | - |
| Deferred income taxes | 123 | 267 |
| **Total noncurrent assets** | **19,853** | **18,572** |
| **Total Assets** | **$ 19,906** | **$ 18,727** |
| | | |
| **LIABILITIES AND SHAREHOLDERS' EQUITY** | | |
| **Current Liabilities** | | |
| Short-term borrowings | $ 132 | $ - |
| Accounts payable – other | 6 | 7 |
| Other | 23 | 274 |
| **Total current liabilities** | **161** | **281** |
| **Noncurrent Liabilities** | | |
| Long-term debt | 350 | 348 |
| Other | 175 | 158 |
| **Total noncurrent liabilities** | **525** | **506** |
| **Common Shareholders' Equity** | | |
| Common stock | 12,632 | 12,198 |
| Reinvested earnings | 6,596 | 5,751 |
| Accumulated other comprehensive income (loss) | (8) | (9) |
| **Total common shareholders' equity** | **19,220** | **17,940** |
| **Total Liabilities and Shareholders' Equity** | **$ 19,906** | **$ 18,727** |

**PG&E CORPORATION**
**SCHEDULE I – CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)**
**CONDENSED STATEMENTS OF CASH FLOWS**
**(in millions)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2017** | **2016** | **2015** |
| **Cash Flows from Operating Activities:** | | | |
| Net income | $ 1,646 | $ 1,393 | $ 874 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |
| Stock-based compensation amortization | 20 | 74 | 66 |
| Equity in earnings of subsidiaries | (1,667) | (1,388) | (852) |
| Deferred income taxes and tax credits-net | 139 | 11 | 10 |
| Current income taxes receivable/payable | (2) | (1) | 5 |
| Other | (75) | (24) | (70) |
| **Net cash provided by operating activities** | **61** | **65** | **33** |
| **Cash Flows From Investing Activities:** | | | |
| Investment in subsidiaries | (455) | (835) | (705) |
| Dividends received from subsidiaries (1) | 784 | 911 | 716 |
| **Net cash provided by (used in) investing activities** | **329** | **76** | **11** |
| **Cash Flows From Financing Activities:** | | | |
| Borrowings (repayments) under revolving credit facilities | 132 | - | - |
| Common stock issued | 395 | 822 | 780 |
| Common stock dividends paid (2) | (1,021) | (921) | (856) |
| **Net cash provided by (used in) financing activities** | **(494)** | **(99)** | **(76)** |
| **Net change in cash and cash equivalents** | **(104)** | **42** | **(32)** |
| **Cash and cash equivalents at January 1** | **106** | **64** | **96** |
| **Cash and cash equivalents at December 31** | **$ 2** | **$ 106** | **$ 64** |
| **Supplemental disclosure of cash flow information** | | | |
| Cash received (paid) for: | | | |
| Interest, net of amounts capitalized | $ (9) | $ (9) | $ (9) |
| Income taxes, net | - | (13) | - |
| **Supplemental disclosure of noncash investing and financing activities** | | | |
| Noncash common stock issuances | $ 21 | $ 20 | $ 21 |
| Common stock dividends declared but not yet paid | - | 248 | 224 |

(1) Because of its nature as a holding company, PG&E Corporation classifies dividends received from subsidiaries as an investing cash flow.
(2) In July and October of 2017, respectively, PG&E Corporation paid quarterly common stock dividends of $0.53 per share. In July and October of 2016 and January and April of 2017, respectively, PG&E Corporation paid quarterly common stock dividends of $0.49 per share. In January, A pril, July, and October of 2015 and January and April of 2016 , respectively, PG&E Corporation paid quarterly common stock dividends of $0.455 per share.

**PG&E Corporation**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 201 7, 2016 , and 201 5**

| (in millions) | | Additions | | | |
|---|---|---|---|---|---|
| **Description** | **Balance at Beginning of Period** | **Charged to Costs and Expenses** | **Charged to Other Accounts** | **Deductions** [2] | **Balance at End of Period** |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2017: | | | | | |
| Allowance for uncollectible accounts [1] | $ 58 | $ 55 | $ - | $ 49 | $ 64 |
| 2016: | | | | | |
| Allowance for uncollectible accounts [1] | $ 54 | $ 50 | $ - | $ 46 | $ 58 |
| 2015: | | | | | |
| Allowance for uncollectible accounts [1] | $ 66 | $ 43 | $ - | $ 55 | $ 54 |

[1] Allowance for uncollectible accounts is deducted from "Accounts receivable - Customers."
[2] Deductions consist principally of write-offs, net of collections of receivables previously written off.

**Pacific Gas and Electric Company**

**SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS**
**For the Years Ended December 31, 201 7 , 201 6 , and 201 5**

| (in millions) | | Additions | | | |
|---|---|---|---|---|---|
| **Description** | **Balance at Beginning of Period** | **Charged to Costs and Expenses** | **Charged to Other Accounts** | **Deductions** [(2)] | **Balance at End of Period** |
| **Valuation and qualifying accounts deducted from assets:** | | | | | |
| 2017: | | | | | |
| Allowance for uncollectible accounts [(1)] | $ 58 | $ 55 | $ - | $ 49 | $ 64 |
| 2016: | | | | | |
| Allowance for uncollectible accounts [(1)] | $ 54 | $ 50 | $ - | $ 46 | $ 58 |
| 2015: | | | | | |
| Allowance for uncollectible accounts [(1)] | $ 66 | $ 43 | $ - | $ 55 | $ 54 |

[(1)] Allowance for uncollectible accounts is deducted from “Accounts receivable - Customers.”
[(2)] Deductions consist principally of write-offs, net of collections of receivables previously written off.

EXHIBIT 10.54

# PG&E Corporation

# 2014 Long-Term Incentive Plan

# PG&E Corporation
# 2014 Long-Term Incentive Plan

(As adopted effective May 12, 2014, and as last amended effective January 1, 2018)

1. **Establishment, Purpose and Term of Plan .**

1.1 **Establishment .** The PG&E Corporation 2014 Long-Term Incentive Plan, as amended from time to time (the " ***Plan*** " ), is hereby established effective as of the date approved by the shareholders of the Company (the "Effective Date"). This Plan replaces the PG&E Corporation 2006 Long-Term Incentive Plan.

1.2 **Purpose .** The purpose of the Plan is to advance the interests of the Participating Company Group and its shareholders by providing an incentive to attract and retain the best qualified personnel to perform services for the Participating Company Group, by motivating such persons to contribute to the growth and profitability of the Participating Company Group, by aligning their interests with interests of the Company's shareholders, and by rewarding such persons for their services by tying a significant portion of their total compensation package to the success of the Company. The Plan seeks to achieve this purpose by providing for Awards in the form of Options, Stock Appreciation Rights, Restricted Stock Awards, Performance Shares, Performance Units, Restricted Stock Units, Deferred Compensation Awards and other Stock-Based Awards as described below.

1.3 **Term of Plan.** The Plan shall continue in effect until the earlier of its termination by the Board or the date on which no Awards remain outstanding under the Plan. However, the term during which all Awards shall be granted, if at all, shall be within ten (10) years from the Effective Date. Moreover, Incentive Stock Options shall not be granted later than February 19, 2024 (ten (10) years from the date on which the Plan was adopted by the Board).

2. **Definitions and Construction .**

2.1 **Definitions.** Whenever used herein, the following terms shall have their respective meanings set forth below:

(a) " ***Affiliate*** " means (i) an entity, other than a Parent Corporation, that directly, or indirectly through one or more intermediary entities, controls the Company or (ii) an entity, other than a Subsidiary Corporation, that is controlled by the Company directly, or indirectly through one or more intermediary entities. For this purpose, the term "control" (including the term "controlled by") means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of the relevant entity, whether through the ownership of voting securities, by contract or otherwise; or shall have such other meaning assigned such term for the purposes of registration on Form S-8 under the Securities Act.

(b) " ***Award*** " means any Option, SAR, Restricted Stock Award, Performance Share, Performance Unit, Restricted Stock Unit or Deferred Compensation Award or other Stock-Based Award granted under the Plan.

(c) " ***Award Agreement*** " means a written agreement between the Company and a Participant setting forth the terms, conditions and restrictions of the Award granted to the Participant (which may also be in electronic form).

(d) " ***Board*** " means the Board of Directors of the Company.

(e) " ***Change in Control*** " means, unless otherwise defined by the Participant's Award Agreement or contract of employment or service, the occurrence of any of the following:

(i) any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act, but excluding any benefit plan for Employees or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the "beneficial owner" (as defined in Rule 13d-3 promulgated under the Exchange Act), of stock of the Company representing thirty percent (30%) or more of the combined voting power of the Company's then outstanding voting stock; or

(ii) during any two consecutive years, individuals who at the beginning of such period constitute the Board cease for any reason to constitute at least a majority of the Board, unless the election, or the nomination for election by the shareholders of the Company, of each new Director was approved by a vote of at least two-thirds (2/3) of the Directors then still in office (1) who were Directors at the beginning of the period or (2) whose election or nomination was previously so approved; or

(iii) the consummation of any consolidation or merger of the Company other than a merger or consolidation which would result in the holders of the voting stock of the Company outstanding immediately prior thereto continuing to directly or indirectly hold at least seventy percent (70%) of the Combined Voting Power of the Company, the surviving entity in the merger or consolidation or the parent of such surviving entity outstanding immediately after the merger or consolidation; or

(iv) (1) the consummation of any sale, lease, exchange or other transfer (in one or a series of related transactions) of all or substantially all of the assets of the Company, or (2) the approval of the Shareholders of the Company of a plan of liquidation or dissolution of the Company.

For purposes of paragraph (iii), the term ***"Combined Voting Power"*** shall mean the combined voting power of the Company's or other relevant entity's then outstanding voting stock.

(f) " ***Code*** " means the Internal Revenue Code of 1986, as amended, and any applicable regulations promulgated thereunder.

(g) " ***Committee*** " means the Compensation Committee or other committee of the Board duly appointed to administer the Plan and having such powers as shall be specified by the Board. If no committee of the Board has been appointed to administer the Plan, the Board shall exercise all of the powers of the Committee granted herein, and, in any event, the Board may in its discretion exercise any or all of such powers.

(h) " ***Company*** " means PG&E Corporation, a California corporation, or any successor corporation thereto.

(i) " ***Consultant*** " means a person engaged to provide consulting or advisory services (other than as an Employee or a member of the Board) to a Participating Company, provided that the identity of such person, the nature of such services or the entity to which such services are provided would not preclude the Company from offering or selling securities to such person pursuant to the Plan in reliance on registration on a Form S-8 Registration Statement under the Securities Act.

(j) " ***Deferred Compensation Award*** " means an award of Stock Units granted to a Participant pursuant to Section 12 of the Plan.

(k) " ***Director*** " means a member of the Board.

(l) " ***Disability*** " means the permanent and total disability of the Participant, within the meaning of Section 22(e)(3) of the Code, except as otherwise set forth in the Plan or an Award Agreement.

(m) " ***Dividend Equivalent*** " means a credit, made at the discretion of the Committee or as otherwise provided by the Plan, to the account of a Participant in an amount equal to the cash dividends paid on one share of Stock for each share of Stock represented by an Award held by such Participant.

(n) " ***Employee*** " means any person treated as an employee (including an Officer or a member of the Board who is also treated as an employee) in the records of a Participating Company and, with respect to any Incentive Stock Option granted to such person, who is an employee for purposes of Section 422 of the Code; provided, however, that neither service as a member of the Board nor payment of a director's fee shall be sufficient to constitute employment for purposes of the Plan. The Company shall determine in good faith and in the exercise of its discretion whether an individual has become or has ceased to be an Employee and the effective date of such individual's employment or termination of employment, as the case may be. For purposes of an individual's rights, if any, under the Plan as of the time of the Company's determination, all such determinations by the Company shall be final, binding and conclusive, notwithstanding that the Company or any court of law or governmental agency subsequently makes a contrary determination.

(o) " ***Exchange Act*** " means the Securities Exchange Act of 1934, as amended.

(p) " ***Fair Market Value*** " means, as of any date, the value of a share of Stock or other property as determined by the Committee, in its discretion, or by the Company, in its discretion, if such determination is expressly allocated to the Company herein, subject to the following:

(i) Except as otherwise determined by the Committee, if, on such date, the Stock is listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be the closing price of a share of Stock as quoted on the New York Stock Exchange or such other national or regional securities exchange or market system constituting the primary market for the Stock, as reported in *The Wall Street Journal* or such other source as the Company deems reliable. If the relevant date does not fall on a day on which the Stock has traded on such securities exchange or market system, the date on which the Fair Market Value shall be established shall be the last day on which the Stock was so traded prior to the relevant date, or such other appropriate day as shall be determined by the Committee, in its discretion.

(ii) Notwithstanding the foregoing, the Committee may, in its discretion, determine the Fair Market Value on the basis of the opening, closing, high, low or average sale price of a share of Stock or the actual sale price of a share of Stock received by a Participant, on such date, the preceding trading day, the next succeeding trading day or an average determined over a period of trading days. The Committee may vary its method of determination of the Fair Market Value as provided in this Section for different purposes under the Plan.

(iii) If, on such date, the Stock is not listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be as determined by the Committee in good faith without regard to any restriction other than a restriction which, by its terms, will never lapse.

(q) " ***Incentive Stock Option*** " means an Option intended to be (as set forth in the Award Agreement) and which qualifies as an incentive stock option within the meaning of Section 422(b) of the Code.

(r) " ***Insider*** " means an Officer, a Director or any other person whose transactions in Stock are subject to Section 16 of the Exchange Act.

(s) **"Net-Exercise"** means a procedure by which the Participant will be issued a number of shares of Stock determined in accordance with the following formula:

X = Y(A-B)/A, where
X = the number of shares of Stock to be issued to the Participant upon exercise of the Option;
Y = the total number of shares with respect to which the Participant has elected to exercise the Option;
A = the Fair Market Value of one (1) share of Stock;
B = the exercise price per share (as defined in the Participant's Award Agreement).

(t) " ***Non-employee Director*** " means a Director who is not an Employee.

(u) " ***Non-employee Director Award*** " means an Award granted to a Non-employee Director pursuant to Section 7 of the Plan.

(v) " ***Nonstatutory Stock Option*** " means an Option not intended to be (as set forth in the Award Agreement) an incentive stock option within the meaning of Section 422(b) of the Code.

(w) " ***Officer*** " means any person designated by the Board as an officer of the Company.

(x) " ***Option*** " means the right to purchase Stock at a stated price for a specified period of time granted to a Participant pursuant to Section 6 or Section 7 of the Plan. An Option may be either an Incentive Stock Option or a Nonstatutory Stock Option.

(y) ***"Option Expiration Date"*** means the date of expiration of the Option's term as set forth in the Award Agreement.

(z) " ***Parent Corporation*** " means any present or future "parent corporation" of the Company in an unbroken chain of corporations ending with the Company in which each of the corporations other than the Company owns stock possessing 50% or more of the total combined voting power of all classes of stock in one of the other corporations in such chain.

(aa) " ***Participant*** " means any eligible person who has been granted one or more Awards.

(bb) " ***Participating Company*** " means the Company or any Parent Corporation, Subsidiary Corporation or Affiliate.

(cc) " ***Participating Company Group*** " means, at any point in time, all entities collectively which are then Participating Companies.

(dd) " ***Performance Award*** " means an Award of Performance Shares or Performance Units.

(ee) " ***Performance Award Formula*** " means, for any Performance Award, a formula or table established by the Committee pursuant to Section 10.3 of the Plan which provides the basis for computing the value of a Performance Award at one or more levels of attainment of the applicable Performance Goal(s) measured as of the end of the applicable Performance Period.

(ff) " ***Performance Goal*** " means a performance goal established by the Committee pursuant to Section 10.3 of the Plan.

(gg) " ***Performance Period*** " means a period established by the Committee pursuant to Section 10.3 of the Plan at the end of which one or more Performance Goals are to be measured.

(hh) " ***Performance Share*** " means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Share, as determined by the Committee, based on performance.

(ii) " ***Performance Unit*** " means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Unit, as determined by the Committee, based upon performance.

(jj) " ***Prior Plan*** " means the PG&E Corporation 2006 Long-Term Incentive Plan.

(kk) " ***Restricted Stock Award*** " means an Award of Restricted Stock.

(ll) " ***Restricted Stock Unit"*** or " ***Stock Unit*** " means a bookkeeping entry representing a right granted to a Participant pursuant to Section 11 or Section 12 of the Plan, respectively, to receive a share of Stock or payment equal to the value of a share of Stock on a date determined in accordance with the provisions of Section 11 or Section 12, as applicable, and the Participant's Award Agreement.

(mm) " ***Restriction Period*** " means the period established in accordance with Section 9.4 of the Plan during which shares subject to a Restricted Stock Award are subject to Vesting Conditions.

(nn) ***"Retirement"*** means termination as an Employee with the Participating Company Group at age 55 or older, provided that the Participant was an Employee for at least five consecutive years prior to the date of such termination.

(oo) " ***Rule 16b-3*** " means Rule 16b-3 under the Exchange Act, as amended from time to time, or any successor rule or regulation.

(pp) " ***SAR*** " or " ***Stock Appreciation Right*** " means a bookkeeping entry representing, for each share of Stock subject to such SAR, a right granted to a Participant pursuant to Section 8 of the Plan to receive payment in any combination of shares of Stock or cash of an amount equal to the excess, if any, of the Fair Market Value of a share of Stock on the date of exercise of the SAR over the exercise price.

(qq) " ***Section 162(m)*** " means Section 162(m) of the Code.

(rr) " ***Section 409A Change in Control*** " means a "change in the ownership or effective control of the corporation, or in the ownership of a substantial portion of the assets of the corporation," within the meaning of Section 409A of the Code, as such definition applies to the Company.

(ss) " ***Securities Act*** " means the Securities Act of 1933, as amended.

(tt) " ***Separation from Service*** " means a Participant's "separation from service," within the meaning of Section 409A of the Internal Revenue Code.

(uu) " ***Service*** " means a Participant's employment or service with the Participating Company Group, whether in the capacity of an Employee, a Director or a Consultant. A Participant's Service shall not be deemed to have terminated merely because of a change in the capacity in which the Participant renders such Service or a change in the Participating Company for which the Participant renders such Service, provided that there is no interruption or termination of the Participant's Service. Furthermore, a Participant's Service shall not be deemed to have terminated if the Participant takes any military leave, sick leave, or other bona fide leave of absence approved by the Company. However, if any such leave taken by a Participant exceeds ninety (90) days, then on the ninety-first (91st) day following the commencement of such leave the Participant's Service shall be deemed terminated and any Incentive Stock Option held by the Participant shall cease to be treated as an Incentive Stock Option and instead shall be treated thereafter as a Nonstatutory Stock Option commencing on the third (3 rd ) month from such deemed termination, unless the Participant's right to return to Service with the Participating Company Group is guaranteed by statute or contract. Notwithstanding the foregoing, unless otherwise designated by the Company or required by law, a leave of absence shall not be treated as Service for purposes of determining vesting under the Participant's Award Agreement. A Participant's Service shall be deemed to have terminated either upon an actual termination of Service or upon the entity for which the Participant performs Service ceasing to be a Participating Company. Subject to the foregoing, the Company, in its discretion, shall determine whether the Participant's Service has terminated and the effective date of such termination.

(vv) ***" Stock "*** means the common stock of the Company, as adjusted from time to time in accordance with Section 4.2 of the Plan.

(ww) ***" Stock-Based Awards "*** means any award that is valued in whole or in part by reference to, or is otherwise based on, the Stock, including dividends on the Stock, but not limited to those Awards described in Sections 6 through 12 of the Plan.

(xx) ***" Subsidiary Corporation "*** means any present or future "subsidiary corporation" of the Company in an unbroken chain of corporations beginning with the Company in which each of the corporations other than the last corporation owns stock possessing 50% or more of the total combined voting power of all classes of stock in one of the other corporations in such chain.

(yy) " ***Substitute Awards"*** means Awards granted or Shares issued by the Company in assumption of, or in substitution or exchange for, awards previously granted, or the right or obligation to make future awards, in each case by a company acquired by the Company or any Subsidiary Corporation or with which the Company or any Subsidiary Corporation combines.

(zz) ***" Ten Percent Owner "*** means a Participant who, at the time an Option is granted to the Participant, owns stock possessing more than ten percent (10%) of the total combined voting power of all classes of stock of a Participating Company (other than an Affiliate) within the meaning of Section 422(b)(6) of the Code.

(aaa) ***" Vesting Conditions "*** mean those conditions established in accordance with Section 9.4 or Section 11.2 of the Plan prior to the satisfaction of which shares subject to a Restricted Stock Award or Restricted Stock Unit Award, respectively, remain subject to forfeiture or a repurchase option in favor of the Company upon the Participant's termination of Service, or other deadline for satisfying such conditions, as applicable.

2.2 **Construction.** Captions and titles contained herein are for convenience only and shall not affect the meaning or interpretation of any provision of the Plan. Except when otherwise indicated by the context, the singular shall include the plural and the plural shall include the singular. Use of the term "or" is not intended to be exclusive, unless the context clearly requires otherwise.

3. **<u>Administration</u> .**

3.1 **Administration by the Committee.** The Plan shall be administered by the Committee. All questions of interpretation of the Plan or of any Award shall be determined by the Committee, and such determinations shall be final and binding upon all persons having an interest in the Plan or such Award.

3.2 **Authority of Officers.** Any Officer shall have the authority to act on behalf of the Company with respect to any matter, right, obligation, determination or election which is the responsibility of or which is allocated to the Company herein, provided the Officer has apparent authority with respect to such matter, right, obligation, determination or election. In addition, to the extent specified in a resolution adopted by the Board, the Chief Executive Officer of the Company shall have the authority to grant Awards to an Employee who is not an Insider and who is receiving a salary below the level which requires approval by the Committee; provided that the terms of such Awards conform to guidelines established by the Committee.

3.3 **Administration with Respect to Insiders.** With respect to participation by Insiders in the Plan, at any time that any class of equity security of the Company is registered pursuant to Section 12 of the Exchange Act, the Plan shall be administered in compliance with the requirements, if any, of Rule 16b-3.

3.4 **Committee Complying with Section 162(m).** While the Company is a "publicly held corporation" within the meaning of Section 162(m), the Board may establish a Committee of "outside directors" within the meaning of Section 162(m) to approve the grant of any Award which might reasonably be anticipated to result in the payment of employee remuneration that would otherwise exceed the limit on employee remuneration deductible for income tax purposes pursuant to Section 162(m).

3.5 **Powers of the Committee .** In addition to any other powers set forth in the Plan and subject to the provisions of the Plan, the Committee shall have the full and final power and authority, in its discretion:

(a) to determine the persons to whom, and the time or times at which, Awards shall be granted and the number of shares of Stock or units to be subject to each Award based on the recommendation of the Chief Executive Officer of the Company (except that Awards to the Chief Executive Officer shall be based on the recommendation of the independent members of the Board in compliance with applicable stock exchange rules, Non-employee Director Awards shall be granted automatically pursuant to Section 7 of the Plan, and other Awards to Non-employee Directors shall be approved by the Board);

(b) to determine the type of Award granted and to designate Options as Incentive Stock Options or Nonstatutory Stock Options;

(c) to determine the Fair Market Value of shares of Stock or other property;

(d) to determine the terms, conditions and restrictions applicable to each Award (which need not be identical) and any shares acquired pursuant thereto, including, without limitation, (i) the exercise or purchase price of shares purchased pursuant to any Award, (ii) the method of payment for shares purchased pursuant to any Award, (iii) the method for satisfaction of any tax withholding obligation arising in connection with any Award, including by the withholding or delivery of shares of Stock, (iv) the timing, terms and conditions of the exercisability or vesting of any Award or any shares acquired pursuant thereto, (v) the Performance Award Formula and Performance Goals applicable to any Award and the extent to which such Performance Goals have been attained,

(vi) the time of the expiration of any Award, (vii) the effect of the Participant's termination of Service on any of the foregoing, and (viii) all other terms, conditions and restrictions applicable to any Award or shares acquired pursuant thereto not inconsistent with the terms of the Plan;

(e) to determine whether an Award will be settled in shares of Stock, cash, or in any combination thereof;

(f) to approve one or more forms of Award Agreement;

(g) to amend, modify, extend, cancel or renew any Award or to waive any restrictions or conditions applicable to any Award or any shares acquired pursuant thereto, subject, in the case of an adversely affected Award, to the affected Participant's consent unless necessary to comply with any applicable law, regulation, or rule;

(h) to accelerate, continue, extend or defer the exercisability or vesting of any Award or any shares acquired pursuant thereto, including with respect to the period following a Participant's termination of Service;

(i) without the consent of the affected Participant and notwithstanding the provisions of any Award Agreement to the contrary, to unilaterally substitute at any time a Stock Appreciation Right providing for settlement solely in shares of Stock in place of any outstanding Option, provided that such Stock Appreciation Right covers the same number of shares of Stock and provides for the same exercise price (subject in each case to adjustment in accordance with Section 4.2) as the replaced Option and otherwise provides substantially equivalent terms and conditions as the replaced Option, as determined by the Committee, and subject to limitations set forth in Section 3.6;

(j) to prescribe, amend or rescind rules, guidelines and policies relating to the Plan, or to adopt sub-plans or supplements to, or alternative versions of, the Plan, including, without limitation, as the Committee deems necessary or desirable to comply with the laws or regulations of or to accommodate the tax policy, accounting principles or custom of, foreign jurisdictions whose citizens may be granted Awards;

(k) to correct any defect, supply any omission or reconcile any inconsistency in the Plan or any Award Agreement and to make all other determinations and take such other actions with respect to the Plan or any Award as the Committee may deem advisable to the extent not inconsistent with the provisions of the Plan or applicable law; and

(l) to delegate to the Chief Executive Officer or the Senior Vice President of Human Resources the authority with respect to ministerial matters regarding the Plan and Awards made under the Plan.

3.6 **Option or SAR Repricing/Buyout.** Notwithstanding anything to the contrary set forth in the Plan, without the affirmative vote of holders of a majority of the shares of Stock cast in person or by proxy at a meeting of the shareholders of the Company at which a quorum representing a majority of all outstanding shares of Stock is present or represented by proxy, the Company shall not approve a program providing for any of the following: (a) the cancellation of outstanding Options or SARs and the grant in substitution therefore of new Options or SARs having a lower exercise price, another Award, cash or a combination thereof (other than in connection with a Change in Control), (b) the amendment of outstanding Options or SARs to reduce the exercise price thereof, (c) the purchase of outstanding unexercised Options or SARs by the Company whether by cash payment or otherwise, or (d) any other action with respect to an Option or SAR that would be treated as a repricing under the rules and regulations of the principal U.S. national securities exchanges on which the Stock is listed. This paragraph shall not be construed to apply to "issuing or assuming a stock option in a transaction to which section 424(a) applies," within the meaning of Section 424 of the Code. For the avoidance of doubt, this Section 3.6 shall not preclude any action taken without shareholder approval that is described in Section 4.2.

3.7 **Indemnification.** In addition to such other rights of indemnification as they may have as members of the Board or the Committee or as officers or employees of the Participating Company Group, members of the Board or the Committee and any officers or employees of the Participating Company Group to whom authority to act for the Board, the Committee or the Company is delegated shall be indemnified by the Company against all reasonable expenses, including attorneys' fees, actually and necessarily incurred in connection with the defense of any action, suit or proceeding, or in connection with any appeal therein, to which they or any of them may be a party by reason of any action taken or failure to act under or in connection with the Plan, or any right granted hereunder, and against all amounts paid by them in settlement thereof (provided such settlement is approved by independent legal counsel selected by the Company) or paid by them in satisfaction of a judgment in any such action, suit or proceeding, except in relation to matters as to which it shall be adjudged in such action, suit or proceeding that such person is liable for gross negligence, bad faith or intentional misconduct in duties; provided, however, that within sixty (60) days after the institution of such action, suit or proceeding, such person shall offer to the Company, in writing, the opportunity at its own expense to handle and defend the same.

4. **Shares Subject to Plan** .

4.1 **Maximum Number of Shares Issuable.** Subject to adjustment as provided in Section 4.2, the maximum aggregate number of shares of Stock that may be issued under the Plan shall be seventeen million (17,000,000) less one share for every one share of Stock covered by an award granted under the Prior Plan after December 31, 2013 and prior to the Effective Date. After the Effective Date, no awards may be granted under the Prior Plan. Shares of Stock issued hereunder shall consist of authorized but unissued or reacquired shares of Stock or any combination thereof. If (i) an outstanding Award for any reason expires or is terminated or canceled without having been exercised or settled in full, or if shares of Stock acquired pursuant to an Award subject to forfeiture or repurchase are forfeited or repurchased by the Company, the shares of Stock allocable to the terminated portion of such Award or such forfeited or repurchased shares of Stock shall again be available for issuance under the Plan; or (ii) after December 31, 2013, an outstanding award under the Prior Plan (whenever granted) for any reason expires or is terminated or canceled without having been exercised or settled in full, or if shares of stock acquired pursuant to an award under the Prior Plan subject to forfeiture or repurchase are forfeited or repurchased by the Company, the shares of stock allocable to the terminated portion of such award or such forfeited or repurchased shares or stock shall again be available for issuance under the Plan (as of December 31, 2013 there were 6,194,819 shares of stock subject to outstanding awards under the Prior Plan). Shares of Stock shall not be deemed to have been issued pursuant to the Plan (and shall again be available for issuance under the Plan) with respect to any portion of an Award (or, after December 31, 2013, an award under the Prior Plan) that is settled in cash (other than in the case of Options or SARs, in which case shares of Stock having a Fair Market Value equal to the cash delivered shall be deemed issued pursuant to the Plan). Upon the exercise of an SAR (or, after December 31, 2013, exercise of an SAR that was granted under the Prior Plan), the gross number of shares for which the SAR is exercised shall be deemed issued and shall not again be available for issuance under the Plan. In the event that (i) any Option or other Award granted hereunder is exercised through the tendering of shares of Stock (either actually or by attestation) or by the withholding of shares by the Company, or (ii) withholding tax liabilities arising from such Award are satisfied by the tendering of shares of Stock (either actually or by attestation) or by the withholding of shares by the Company, then in each such case (other than in the case of such shares tendered or withheld in connection with the exercise of Options or SARs) the shares of Stock so tendered or withheld shall be added to the shares available for grant under the Plan on a one-for-one basis. In the event that after December 31, 2013, (i) any option or award under the Prior Plan is exercised through the tendering of shares (either actually or by attestation) or by the withholding of shares by the Company, or (ii) withholding tax liabilities arising from such options or awards are satisfied by the tendering of shares (either actually or by attestation) or by the withholding of shares by the Company, then in each such case (other than in the case of such shares tendered or withheld in connection with the exercise of Options or SARs) the shares so tendered or withheld shall be added to the shares available for grant under the Plan on a one-for-one basis.

4.2 **Adjustments for Changes in Capital Structure .** Subject to any required action by the shareholders of the Company, Section 409A of the Code and Section 162(m) of the Code for Awards intended to comply with the "qualified performance-based compensation" exception thereunder, in the event of any change in the Stock effected without receipt of consideration by the Company, whether through merger, consolidation, reorganization, reincorporation, recapitalization, reclassification, stock dividend, stock split, reverse stock split, split-up, split-off, spin-off, combination of shares, exchange of shares, or similar change in the capital structure of the Company, or in the event of payment of a dividend or distribution to the shareholders of the Company in a form other than Stock (excepting normal cash dividends) that has a material effect on the Fair Market Value of shares of Stock, appropriate adjustments shall be made in the number and kind of shares subject to the Plan and to any outstanding Awards, in the Award limits set forth in Section 5.4 , and in the exercise or purchase price per share under any outstanding Award in order to prevent dilution or enlargement of Participants' rights under the Plan. For purposes of the foregoing, conversion of any convertible securities of the Company shall not be treated as "effected without receipt of consideration by the Company." Any fractional share resulting from an adjustment pursuant to this Section 4.2 shall be rounded down to the nearest whole number. The Committee in its sole discretion, may also make such adjustments in the terms of any Award to reflect, or related to, such changes in the capital structure of the Company or distributions as it deems appropriate, including modification of Performance Goals, Performance Award Formulas and Performance Periods, subject to Section 162(m) of the Code for Awards intended to qualify as "performance-based compensation" thereunder. The adjustments determined by the Committee pursuant to this Section 4.2 shall be final, binding and conclusive.

4.3 **Substitute Awards** . To the extent permitted under the rules of the applicable stock exchange on which the Stock is listed, Substitute Awards shall not reduce the shares of Stock authorized for grant under the Plan, nor shall Shares subject to a Substitute Award be added to the shares of Stock available for Awards under the Plan as provided above. Additionally, subject to the rules of the applicable stock exchange on which the Stock is listed, in the event that a company acquired by the Company or any Subsidiary Corporation or with which the Company or any Subsidiary Corporation combines has shares available under a pre-existing plan approved by shareholders and not adopted in contemplation of such acquisition or combination, the shares available for grant pursuant to the terms of such pre-existing plan (as adjusted, to the extent appropriate, using the exchange ratio or other adjustment or valuation ratio or formula used in such acquisition or combination to determine the consideration payable to the holders of common stock of the entities party to such acquisition or combination) may be used for Awards under the Plan and shall not reduce the shares authorized for grant under the Plan (and shares subject to such Awards shall not be added to the shares available for Awards under the Plan as provided in the paragraphs above); provided that Awards using such available shares shall not be made after the date awards or grants could have been made under the terms of the pre-existing plan, absent the acquisition or combination, and shall only be made to individuals who were not Employees or Directors prior to such acquisition or combination.

5. **Eligibility and Award Limitations .**

5.1 **Persons Eligible for Awards.** Awards may be granted only to Employees, Consultants and Directors (including Non-employee Directors). For purposes of the foregoing sentence, "Employees," "Consultants" and "Directors" shall include prospective Employees, prospective Consultants and prospective Directors to whom Awards are granted in connection with written offers of an employment or other service relationship with the Participating Company Group; provided, however, that no Stock subject to any such Award shall vest, become exercisable or be issued prior to the date on which such person commences Service. A Non-employee Director Award may be granted only to a person who, at the time of grant, is a Non-employee Director.

5.2 **Participation.** Awards other than Non-employee Director Awards are granted solely at the discretion of the Committee. Eligible persons may be granted more than one Award. However , eligibility in accordance with this Section shall not entitle any person to be granted an Award, or, having been granted an Award, to be granted an additional Award.

5.3 **Incentive Stock Option Limitations.**

(a) ***Persons Eligible.*** An Incentive Stock Option ("ISO") may be granted only to a person who, on the effective date of grant, is an Employee of the Company, a Parent Corporation or a Subsidiary Corporation (each being an ***" ISO-Qualifying Corporation "*** ). Any person who is not an Employee of an ISO-Qualifying Corporation on the effective date of the grant of an Option to such person may be granted only a Nonstatutory Stock Option. An Incentive Stock Option granted to a prospective Employee upon the condition that such person become an Employee of an ISO-Qualifying Corporation shall be deemed granted effective on the date such person commences Service with an ISO-Qualifying Corporation, with an exercise price determined as of such date in accordance with Section 6.1.

(b) ***Fair Market Value Limitation.*** To the extent that options designated as Incentive Stock Options (granted under all stock option plans of the Participating Company Group, including the Plan) become exercisable by a Participant for the first time during any calendar year for stock having a Fair Market Value greater than One Hundred Thousand Dollars ($100,000), the portion of such options which exceeds such amount shall be treated as Nonstatutory Stock Options. For purposes of this Section, options designated as Incentive Stock Options shall be taken into account in the order in which they were granted, and the Fair Market Value of stock shall be determined as of the time the option with respect to such stock is granted. If the Code is amended to provide for a limitation different from that set forth in this Section, such different limitation shall be deemed incorporated herein effective as of the date and with respect to such Options as required or permitted by such amendment to the Code. If an Option is treated as an Incentive Stock Option in part and as a Nonstatutory Stock Option in part by reason of the limitation set forth in this Section, the Participant may designate which portion of such Option the Participant is exercising. In the absence of such designation, the Participant shall be deemed to have exercised the Incentive Stock Option portion of the Option first. Upon exercise, shares issued pursuant to each such portion shall be separately identified.

5.4 **Award Limits.**

(a) ***Maximum Number of Shares Issuable Pursuant to Incentive Stock Options.*** Subject to adjustment as provided in Section 4.2, the maximum aggregate number of shares of Stock that may be issued under the Plan pursuant to the exercise of Incentive Stock Options shall not exceed the number of shares set forth in the first sentence of Section 4.1 plus, to the extent allowable under Section 422 of the Code and the Treasury Regulations thereunder, any shares of Stock that again become available for issuance pursuant to the remaining provisions of Section 4.1.

(b) ***Section 162(m) Award Limits.*** Subject to adjustment as provided in Section 4.2, no Participant may be granted (i) Options or Stock Appreciation Rights during any calendar year with respect to more than 800,000 shares of Stock in the aggregate, and (ii) during any calendar year one or more Restricted Stock Awards, Restricted Stock Unit Awards or Performance Share Awards that are intended to comply with the performance-based exception under Code Section 162(m) for more than 1,600,000 shares of Stock in the aggregate; provided that, for this purpose, such limit shall be applied based on the maximum number of shares of Stock that may be earned under the applicable Award(s). During any calendar year no Participant may be granted Performance Units or other Awards that are intended to comply with the performance-based exception under Code Section 162(m) and are denominated in cash under which more than $20,000,000 may be earned in the aggregate. Each of the limitations in this section shall be multiplied by two with respect to Awards granted to a Participant during the first calendar year in which the Participant commences employment with the Company and its Subsidiaries. If an Award is cancelled, the cancelled Award shall continue to be counted toward the applicable limitation in this Section.

(c) ***Non-employee Director Award Limits.*** No Non-employee Director shall be granted Awards (including Non-employee Director Awards) in any calendar year having an aggregate Grant Date value in excess of $400,000. For this purpose, Restricted Stock Units, Restricted Stock Awards, Performance Awards, and other Awards shall be valued based on the Fair Market Value on the Grant Date of the maximum number of shares of Stock or dollars, as applicable, covered thereby and Options and SARs shall be valued using a Black-Scholes or other accepted valuation model, in each case, using reasonable assumptions.

5.5 **Dividends and Dividend Equivalents.** Notwithstanding anything herein to the contrary, cash dividends, stock and any other property (other than cash) distributed as a dividend, a Dividend Equivalent or otherwise with respect to any Award that vests based on achievement of Performance Goals (a) shall either (i) not be paid or credited or (ii) be accumulated, (b) shall be subject to restrictions and risk of forfeiture to the same extent as the underlying Award with respect to which such cash, stock or other property has been distributed and (c) shall be paid after such restrictions and risk of forfeiture lapse in accordance with the terms of the applicable Award Agreement.

6. **Terms and Conditions of Options .**

Options shall be evidenced by Award Agreements specifying the number of shares of Stock covered thereby, in such form as the Committee shall from time to time establish. No Option or purported Option shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Options may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

6.1 **Exercise Price .** The exercise price for each Option shall be established in the discretion of the Committee; provided, however, that (a) the exercise price per share shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the Option and (b) no Incentive Stock Option granted to a Ten Percent Owner shall have an exercise price per share less than one hundred ten percent (110%) of the Fair Market Value of a share of Stock on the effective date of grant of the Option. Notwithstanding the foregoing, an Option (whether an Incentive Stock Option or a Nonstatutory Stock Option) may be granted with an exercise price lower than the minimum exercise price set forth above if such Option is granted as a Substitute Award, except as would result in taxation under Section 409A or loss of ISO status.

6.2 **Exercisability and Term of Options .** Options shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such Option; provided, however, that (a) no Option shall be exercisable after the expiration of ten (10) years after the effective date of grant of such Option, (b) no Incentive Stock Option granted to a Ten Percent Owner shall be exercisable after the expiration of five (5) years after the effective date of grant of such Option, and (c) no Option granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service. Subject to the foregoing, unless otherwise specified by the Committee in the grant of an Option, any Option granted hereunder shall terminate ten (10) years after the effective date of grant of the Option, unless earlier terminated in accordance with its provisions.

6.3 **Payment of Exercise Price.**

(a) ***Forms of Consideration Authorized.*** Except as otherwise provided below, payment of the exercise price for the number of shares of Stock being purchased pursuant to any Option shall be made (i) in cash, by check or in cash equivalent, (ii) by tender to the Company, or attestation to the ownership, of shares of Stock owned by the Participant having a Fair Market Value not less than the exercise price, (iii) by delivery of a properly executed notice of exercise together with irrevocable instructions to a broker providing for the assignment to the Company of the proceeds of a sale or loan with respect to some or all of the shares being acquired upon the exercise of the Option (including, without limitation, through an exercise complying with the provisions of Regulation T as promulgated from time to time by the Board of Governors of the Federal Reserve System) (a ***" Cashless Exercise "***), (iv) by delivery of a properly executed notice of exercise electing a Net-Exercise, (v) by such other consideration as may be approved by the Committee from time to time to the extent permitted by applicable law, or (vi) by any combination thereof. The Committee may at any time or from time to time grant Options which do not permit all of the foregoing forms of consideration to be used in payment of the exercise price or which otherwise restrict one or more forms of consideration. Notwithstanding the foregoing, an Award Agreement may provide that if on the last day of the term of an Option the Fair Market Value of one share exceeds the option price per share, the Participant has not exercised the Option (or a tandem Stock Appreciation Right, if applicable) and the Option has not expired, the Option, to the extent vested, shall be deemed to have been exercised by the Participant on such day with payment made by withholding shares otherwise issuable in connection with the exercise of the Option. In such event, the Company shall deliver to the Participant the number of shares for which the Option was deemed exercised, less the number of shares required to be withheld for the payment of the total purchase price and required withholding taxes; provided, however, any fractional share shall be settled in cash.

(b) ***Limitations on Forms of Consideration.***

(i) **Tender of Stock.** Notwithstanding the foregoing, an Option may not be exercised by tender to the Company, or attestation to the ownership, of shares of Stock to the extent such tender or attestation would constitute a violation of the provisions of any law, regulation or agreement restricting the redemption of the Company's stock.

(ii) **Cashless Exercise.** The Company reserves, at any and all times, the right, in the Company's sole and absolute discretion, to establish, decline to approve or terminate any program or procedures for the exercise of Options by means of a Cashless Exercise, including with respect to one or more Participants specified by the Company notwithstanding that such program or procedures may be available to other Participants.

6.4 **Effect of Termination of Service.**

(a) ***Option Exercisability .*** Subject to earlier termination of the Option as otherwise provided herein and unless otherwise provided by the Committee, an Option shall be exercisable after a Participant's termination of Service only during the applicable time periods provided in the Award Agreement.

(b) ***Extension if Exercise Prevented by Law .*** Notwithstanding the foregoing, unless the Committee provides otherwise in the Award Agreement, if the exercise of an Option within the applicable time periods is prevented by the provisions of Section 15 below, the Option shall remain exercisable until three (3) months (or such longer period of time as determined by the Committee, in its discretion) after the date the Participant is notified by the Company that the Option is exercisable, but in any event no later than the earlier of the Option Expiration Date and the tenth anniversary of the date of grant of the Option.

(c) ***Extension if Exercise Prohibited by Law .*** Notwithstanding the foregoing, in the event that on the last business day of the term of an Option (other than an Incentive Stock Option) the exercise of the Option is prohibited by applicable law, the term of the Option shall be extended for a period of thirty (30) days following the end of the legal prohibition.

7. **Terms and Conditions of Non-employee Director Awards .**

Non-employee Director Awards granted under this Plan shall be automatic and non-discretionary and shall comply with and be subject to the terms and conditions set forth in this Section 7.

The grant date for all Non-employee Director awards to be made under this Section 7 shall be the later of (1) the date on which the independent inspector of election certifies the results of the annual election of directors by shareholders of PG&E Corporation or (2) the date that this Plan becomes effective and grants can be made consistent with legal requirements; provided, however, that in extraordinary circumstances, the grant shall be delayed until the first business day of the next open trading window period following certification of the director election results, as determined by the General Counsel of PG&E Corporation (the "Grant Date").

Grants made pursuant to this Section 7, but prior to January 1, 2015, shall be subject to the terms of Section 7 of the Prior Plan as in effect prior to the Effective Date, provided, however, that such grants shall be deemed made under this Plan.

7.1 **Grant of Restricted Stock Unit.**

(a) Timing and Amount of Grant. Each person who is a Non-employee Director on the Grant Date (other than a Non-employee Director who is serving as the Company's non-executive Chair of the Board) shall receive a grant of Restricted Stock Units with the number of Restricted Stock Units determined by dividing $140,000 by the Fair Market Value of the Stock on the Grant Date (rounded down to the nearest whole Restricted Stock Unit). Each Non-employee Director who also serves as the Company's non-executive Chair of the Board on the Grant Date shall receive a grant of Restricted Stock Units with the number of Restricted Stock Units determined by dividing $220,000 by the Fair Market Value of the Stock on the Grant Date (rounded down to the nearest whole Restricted Stock Unit.) The Restricted Stock Units awarded to a Non-employee Director shall be credited to the director's Restricted Stock Unit account. Each Restricted Stock Unit awarded to a Non-employee Director in accordance with this Section 7.1(a) shall be deemed to be equal to one (1) (or fraction thereof) share of Stock on the Grant Date, and the value of the Restricted Stock Unit shall thereafter fluctuate in value in accordance with the Fair Market Value of the Stock. No person shall receive more than one grant of Restricted Stock Units pursuant to this Section 7.1(a) during any calendar year.

(b) ***Dividend Rights .*** Each Non-employee Director's Restricted Stock Unit account shall be credited quarterly on each dividend payment date with additional shares of Restricted Stock Units (including fractions computed to three decimal places) determined by dividing (1) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the account by (2) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award.

(c) ***Vesting and Settlement of Restricted Stock Units .*** Restricted Stock Units shall vest on the earlier of (i) the first anniversary of the Grant Date or (ii) the last day of the director's elected term (the normal vesting date). Restricted Stock Units credited to a Non-employee Director's Restricted Stock Unit account shall, to the extent vested, be settled in a lump sum by the issuance of an equal number of shares of Stock, rounded down to the nearest whole share, upon the earliest of (i) the first anniversary of the Grant Date (normal settlement date), (ii) the Non-employee Director's death, (iii) the Non-employee Director's Disability (within the meaning of Section 409A of the Code), or (iv) the Non-employee Director's Separation from Service following a Change in Control. However, commencing with Restricted Stock Units having a Grant Date in 2015, a Non-employee Director may irrevocably elect, no later than December 31 of the calendar year prior to the Grant Date of the Restricted Stock Units (or such later time permitted by Section 409A) to have the Non-employee Director's Restricted Stock Unit account settled in (1) a series of 10 approximately equal annual installments (which shall be separate payments for purposes of Section 409A) commencing in January of any year following the normal settlement date, or (2) a lump sum in January of any future year following the normal settlement date. In the event that the Non-employee Director elects settlement of the Restricted Stock Units in accordance with the immediately preceding sentence, the Restricted Stock Units shall be earlier settled in a lump sum, to the extent vested, upon the occurrence of any of the events set forth in Section 7.1(c)(ii) through 7.1(c)(iv) prior to the elected settlement date (or commencement thereof in the case of settlement in 10 equal annual installments). In the event that a Non-employee Director elects to have the Non-employee Director's Restricted Stock Unit account settled in a series of 10 approximately equal annual installments commencing in January of any year following the normal settlement date and one of the events set forth in Section 7.1(c)(ii) through 7.1(c)(iv) occurs after commencement of such installments but prior to full settlement of the Non-employee Director's Restricted Stock Units, then any remaining unsettled Restricted Stock Units will be settled in a lump sum upon the occurrence of the applicable event but only to the extent that such acceleration would not result in the imposition of taxation under Section 409A. The Board may authorize other deferral alternatives with respect to Restricted Stock Units granted to Non-employee Directors, provided that such deferral alternatives comply with the deferral timing and other requirements of Section 409A. Such deferral alternatives may include, without limitation, deferral until the Non-employee Director's separation from service or until the January following such separation.

7.2 **Effect of Termination of Service as a Non-employee Director.**

(a) ***Forfeiture of Award .*** If the Non-employee Director has a Separation from Service prior to the normal vesting date, all Restricted Stock Units credited to the Participant's account that have not vested in accordance with Section 7.2(b) or 7.3 shall be forfeited to the Company and from and after the date of such Separation from Service, and the Participant shall cease to have any rights with respect thereto; provided, however, that if the Non-employee Director Separates from Service due to a pending Disability determination, such forfeiture shall not occur until a finding that such Disability has not occurred.

(b) ***Death or Disability*** . If the Non-employee Director becomes "disabled," within the meaning of Section 409A of the Code or in the event of the Non-employee Director's death, all Restricted Stock Units credited to the Non-employee Director's account shall immediately vest and become payable, in accordance with Section 7.1(c), to the Participant (or the Participant's legal representative or other person who acquired the rights to the Restricted Stock Units by reason of the Participant's death) in the form of a number of shares of Stock equal to the number of Restricted Stock Units credited to the Restricted Stock Unit account, rounded down to the nearest whole share.

(c) Notwithstanding the provisions of Section 7.1(c) above, the Board, in its sole discretion, may amend this Section 7 or establish different terms and conditions pertaining to Non-employee Director Awards, in compliance with Section 409A of the Code.

7.3 **Effect of Change in Control on Non-employee Director Awards.** In the event a Non-employee Director ceases to be on the Board for any reason (other than resignation), following the occurrence of a Change in Control, all Restricted Stock Units shall immediately vest but shall not be settled until such time set forth in Section 7.1(c) occurs.

7.4 **Other Awards to Non-employee Directors** . Notwithstanding anything to the contrary set forth in this Plan, subject to Section 5.4(c) of the Plan, Non-employee Directors shall be eligible to receive all types of Awards under the Plan in addition to or instead of Non-employee Director Awards, as may be determined by the Board.

8. **Terms and Conditions of Stock Appreciation Rights .**

Stock Appreciation Rights shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No SAR or purported SAR shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing SARs may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

8.1 **Types of SARs Authorized.** SARs may be granted in tandem with all or any portion of a related Option (a ***" Tandem SAR "*** ) or may be granted independently of any Option (a ***" Freestanding SAR "*** ). A Tandem SAR may be granted either concurrently with the grant of the related Option or at any time thereafter prior to the complete exercise, termination, expiration or cancellation of such related Option.

8.2 **Exercise Price.** The exercise price for each SAR shall be established in the discretion of the Committee; provided, however, that (other than in connection with Substitute Awards granted in accordance with Code Section 424(a)): (a) the exercise price per share subject to a Tandem SAR shall be the exercise price per share under the related Option and (b) the exercise price per share subject to a Freestanding SAR shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the SAR.

8.3 **Exercisability and Term of SARs.**

(a) ***Tandem SARs.*** Tandem SARs shall be exercisable only at the time and to the extent, and only to the extent, that the related Option is exercisable, subject to such provisions as the Committee may specify where the Tandem SAR is granted with respect to less than the full number of shares of Stock subject to the related Option.

(b) ***Freestanding SARs.*** Freestanding SARs shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such SAR; provided, however, that no Freestanding SAR shall be exercisable after the expiration of ten (10) years after the effective date of grant of such SAR.

(c) ***Extension if Exercise Prevented by Law .*** Notwithstanding the foregoing, unless the Committee provides otherwise in the Award Agreement, if the exercise of an SAR within the applicable time periods is prevented by the provisions of Section 15 below, the SAR shall remain exercisable until three (3) months (or such longer period of time as determined by the Committee, in its discretion) after the date the Participant is notified by the Company that the SAR is exercisable, but in any event no later than the earlier of the date of expiration of the SAR's term (as set forth in the applicable Award Agreement) and the tenth anniversary of the date of grant of the SAR.

(d) ***Extension if Exercise Prohibited by Law .*** Notwithstanding the foregoing, in the event that on the last business day of the term of an SAR the exercise of the SAR is prohibited by applicable law, the term shall be extended for a period of thirty (30) days following the end of the legal prohibition.

8.4 **Deemed Exercise of SARs.** An Award Agreement may provide that if on the last day of the term of an SAR the Fair Market Value of one share exceeds the grant price per share of the Stock Appreciation Right, the Participant has not exercised the SAR or the tandem Option (if applicable), and the SAR has not otherwise expired, the SAR, to the extent then vested, shall be deemed to have been exercised by the Participant on such day. In such event, the Company shall make payment to the Participant in accordance with this Section, reduced by the number of shares (or cash) required for withholding taxes; any fractional share shall be settled in cash.

8.5 **Effect of Termination of Service.** Subject to earlier termination of the SAR as otherwise provided herein and unless otherwise provided by the Committee in the grant of an SAR and set forth in the Award Agreement, an SAR shall be exercisable after a Participant's termination of Service only as provided in the Award Agreement.

9. **Terms and Conditions of Restricted Stock Awards .**

Restricted Stock Awards shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Award or purported Restricted Stock Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

9.1 **Types of Restricted Stock Awards Authorized.** Restricted Stock Awards may or may not require the payment of cash compensation for the stock. Restricted Stock Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4 or other performance conditions established by the Committee. If either the grant of a Restricted Stock Award or the lapsing of the Restriction Period is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) for Awards intended to comply with the "qualified performance-based compensation" exception under Section 162(m) of the Code.

9.2 **Purchase Price.** The purchase price, if any, for shares of Stock issuable under each Restricted Stock Award and the means of payment shall be established by the Committee in its discretion.

9.3 **Purchase Period.** A Restricted Stock Award requiring the payment of cash consideration shall be exercisable within a period established by the Committee; provided, however, that no Restricted Stock Award granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service.

9.4 **Vesting and Restrictions on Transfer.** Shares issued pursuant to any Restricted Stock Award may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4, as shall be established by the Committee and set forth in the Award Agreement evidencing such Award. During any Restriction Period in which shares acquired pursuant to a Restricted Stock Award remain subject to Vesting Conditions, such shares may not be sold, exchanged, transferred, pledged, assigned or otherwise disposed of other than as provided in the Award Agreement or as provided in Section 18. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

9.5 **Voting Rights, Dividends and Distributions.** Except as provided in this Section, Section 9.4, Section 5.5, and any Award Agreement, during the Restriction Period applicable to shares subject to a Restricted Stock Award, the Participant shall have all of the rights of a shareholder of the Company holding shares of Stock, including the right to vote such shares and to receive all dividends and other distributions paid with respect to such shares. However, in the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2, any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant is entitled by reason of the Participant's Restricted Stock Award shall be immediately subject to the same Vesting Conditions as the shares subject to the Restricted Stock Award with respect to which such dividends or distributions were paid or adjustments were made.

9.6 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any shares acquired by the Participant pursuant to a Restricted Stock Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service in exchange for the payment of the purchase price, if any, paid by the Participant. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company.

10. **Terms and Conditions of Performance Awards .**

Performance Awards shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No Performance Award or purported Performance Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Performance Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions to the extent required under Section 162(m). Notwithstanding the foregoing, Awards that are not intended to comply with the "qualified performance-based compensation" exception under Section 162(m) may be subject to such other terms and conditions (which may be different from the terms and conditions set forth in this Section 10) as shall be determined by the Committee in its sole discretion.

10.1 **Types of Performance Awards Authorized.** Performance Awards may be in the form of either Performance Shares or Performance Units. Each Award Agreement evidencing a Performance Award shall specify the number of Performance Shares or Performance Units subject thereto, the Performance Award Formula, the Performance Goal(s) and Performance Period applicable to the Award, and the other terms, conditions and restrictions of the Award.

10.2 **Initial Value of Performance Shares and Performance Units.** Unless otherwise provided by the Committee in granting a Performance Award, each Performance Share shall have an initial value equal to the Fair Market Value of one (1) share of Stock, subject to adjustment as provided in Section 4.2, on the effective date of grant of the Performance Share. Each Performance Unit shall have an initial value determined by the Committee. The final value payable to the Participant in settlement of a Performance Award determined on the basis of the applicable Performance Award Formula will depend on the extent to which Performance Goals established by the Committee are attained within the applicable Performance Period established by the Committee.

10.3 **Establishment of Performance Period, Performance Goals and Performance Award Formula.** In granting each Performance Award, the Committee shall establish in writing the applicable Performance Period, Performance Award Formula and one or more Performance Goals which, when measured at the end of the Performance Period, shall determine on the basis of the Performance Award Formula the final value of the Performance Award to be paid to the Participant. To the extent compliance with the requirements under Section 162(m) with respect to "performance-based compensation" is desired, the Committee shall establish the Performance Goal(s) and Performance Award Formula applicable to each Performance Award no later than the earlier of (a) the date ninety (90) days after the commencement of the applicable Performance Period or (b) the date on which 25% of the Performance Period has elapsed, and, in any event, at a time when the outcome of the Performance Goals remains substantially uncertain. Once established, the Performance Goals and Performance Award Formula for Awards intended to comply with the "qualified performance-based compensation" exception under Section 162(m) shall not be changed during the Performance Period, except as would result in the exercise of negative discretion by the Committee to reduce the amount of the Award otherwise payable as permitted under Section 162(m). The Company shall notify each Participant granted a Performance Award of the terms of such Award, including the Performance Period, Performance Goal(s) and Performance Award Formula.

10.4 **Measurement of Performance Goals.** Performance Goals shall be established by the Committee on the basis of targets to be attained ( " ***Performance Targets*** " ) with respect to one or more measures of business or financial performance (each, a " ***Performance Measure*** " ), subject to the following:

(a) ***Performance Measures.*** Performance Measures shall be calculated with respect to the Company and/or each Subsidiary Corporation and/or such division or other business unit as may be selected by the Committee, or may be based upon performance relative to performance of other companies or upon comparisons of any of the indicators of performance relative to performance of other companies. Performance Measures may be based upon one or more of the following objectively defined and non-discretionary business criteria and any other objectively verifiable and non-discretionary adjustments permitted and pre-established by the Committee in accordance with Section 162(m), as determined by the Committee: (i) sales revenue; (ii) gross margin; (iii) operating margin; (iv) operating income; (v) pre-tax profit; (vi) earnings before interest, taxes and depreciation and amortization (EBITDA)/adjusted EBITDA; (vii) net income; (viii) expenses; (ix) the market price of the Stock; (x) earnings per share; (xi) return on shareholder equity or assets; (xii) return on capital; (xiii) return on net assets; (xiv) economic profit or economic value added (EVA); (xv) market share; (xvi) customer satisfaction; (xvii) safety; (xviii) total shareholder return; (xix) earnings; (xx) cash flow; (xxi) revenue; (xxii) profits before interest and taxes; (xxiii) profit/loss; (xxiv) profit margin; (xxv) working capital; (xxvi) price/earnings ratio; (xxvii) debt or debt-to-equity; (xxviii) accounts receivable; (xxix) write-offs; (xxx) cash; (xxxi) assets; (xxxii) liquidity; (xxxiii) earnings from operations; (xxxiv) operational reliability; (xxxv) environmental performance; (xxxvi) funds from operations; (xxxvii) adjusted revenues; (xxxviii) free cash flow; (xxxix) core earnings; or (xxxx) operational performance.

(b) ***Performance Targets.*** Performance Targets may include a minimum, maximum, target level and intermediate levels of performance, with the final value of a Performance Award determined under the applicable Performance Award Formula by the level attained during the applicable Performance Period. A Performance Target may be stated as an absolute value or as a value determined relative to a standard selected by the Committee.

10.5 **Settlement of Performance Awards.**

(a) ***Determination of Final Value.*** As soon as practicable, but no later than the 15th day of the third month following the completion of the Performance Period applicable to a Performance Award (or such shorter period set forth in an Award Agreement), the Committee shall certify in writing the extent to which the applicable Performance Goals have been attained and the resulting final value of the Award earned by the Participant and to be paid upon its settlement in accordance with the applicable Performance Award Formula no later than the 15 th day of the third month following the completion of such Performance Period (or such shorter period set forth in an Award Agreement).

(b) ***Discretionary Adjustment of Award Formula.*** In its discretion, the Committee may, either at the time it grants a Performance Award or at any time thereafter, provide for the positive or negative adjustment of the Performance Award Formula applicable to a Performance Award that is not intended to constitute "qualified performance-based compensation" to a "covered employee" within the meaning of Section 162(m) (a " ***Covered Employee*** " ) to reflect such Participant's individual performance in his or her position with the Company or such other factors as the Committee may determine. With respect to a Performance Award intended to constitute qualified performance-based compensation to a Covered Employee, the Committee shall have the discretion to reduce (but not increase) some or all of the value of the Performance Award that would otherwise be paid to the Covered Employee upon its settlement notwithstanding the attainment of any Performance Goal and the resulting value of the Performance Award determined in accordance with the Performance Award Formula.

(c) ***Payment in Settlement of Performance Awards.*** As soon as practicable following the Committee's determination and certification in accordance with Sections 10.5(a) and (b) but, in any case, no later than the 15th day of the third month following completion of the Performance Period applicable to a Performance Award (or such shorter period set forth in an Award Agreement), payment shall be made to each eligible Participant (or such Participant's legal representative or other person who acquired the right to receive such payment by reason of the Participant's death) of the final value of the Participant's Performance Award. Payment of such amount shall be made in cash, shares of Stock, or a combination thereof as determined by the Committee.

10.6 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Performance Share Awards until the date of the issuance of such shares, if any (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Performance Share Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which the Performance Shares are settled or forfeited. Such Dividend Equivalents, if any, shall be credited to the Participant in the form of additional whole Performance Shares as of the date of payment of such cash dividends on Stock. The number of additional Performance Shares (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Performance Shares previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Dividend Equivalents credited in connection with Performance Shares shall be subject to Section 5.5 of the Plan. Settlement of Dividend Equivalents may be made in cash, shares of Stock, or a combination thereof as determined by the Committee, and may be paid on the same basis as settlement of the related Performance Share as provided in Section 10.5. Dividend Equivalents shall not be paid with respect to Performance Units. In the event of an adjustment described in Section 4.2, the adjusted Performance Share Award shall be immediately subject to the same Performance Goals as are applicable to the Award.

10.7 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Performance Award and set forth in the Award Agreement, the effect of a Participant's termination of Service on the Performance Award shall be as follows:

(a) ***Death or Disability.*** If the Participant's Service terminates because of the death or Disability of the Participant before the completion of the Performance Period applicable to the Performance Award, the final value of the Participant's Performance Award shall be determined by the extent to which the applicable Performance Goals have been attained with respect to the entire Performance Period and shall be prorated based on the number of months of the Participant's Service during the Performance Period. Payment shall be made following the end of the Performance Period in any manner permitted by Section 10.5.

(b) ***Other Termination of Service.*** If the Participant's Service terminates for any reason except death or Disability before the completion of the Performance Period applicable to the Performance Award, such Award shall be forfeited in its entirety; provided, however, that in the event of termination of the Participant's Service for other reasons, the Committee, in its sole discretion, may waive the automatic forfeiture of all or any portion of any such Award, to the extent consistent with the preservation of the tax deductibility of awards pursuant to Section 162(m) of the Code.

11. **Terms and Conditions of Restricted Stock Unit Awards** .

Restricted Stock Unit Awards shall be evidenced by Award Agreements specifying the number of Restricted Stock Units subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Unit Award or purported Restricted Stock Unit Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Units may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

11.1 **Grant of Restricted Stock Unit Awards.** Restricted Stock Unit Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4. If either the grant of a Restricted Stock Unit Award or the Vesting Conditions with respect to such Award is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) for Awards intended to comply with the "qualified performance-based compensation" exception under Section 162(m).

11.2 **Vesting.** Restricted Stock Units may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4, as shall be established by the Committee and set forth in the Award Agreement evidencing such Award.

11.3 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Restricted Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Restricted Stock Unit Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Restricted Stock Units held by such Participant are settled. Such Dividend Equivalents, if any, shall be paid by crediting the Participant with additional whole Restricted Stock Units as of the date of payment of such cash dividends on Stock. The number of additional Restricted Stock Units (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award, provided that Dividend Equivalents may be settled in cash, shares of Stock, or a combination thereof as determined by the Committee and set forth in the Award Agreement. In the event of an adjustment as described in Section 4.2, the Participant's adjusted Restricted Stock Unit Award shall be immediately subject to the same Vesting Conditions as are applicable to the Award.

11.4 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Unit Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any Restricted Stock Units pursuant to the Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service.

11.5 **Settlement of Restricted Stock Unit Awards .** The Company shall issue to a Participant on the date on which Restricted Stock Units subject to the Participant's Restricted Stock Unit Award vest or on such other date determined by the Committee, in its discretion, and set forth in the Award Agreement one (1) share of Stock (and/or any other new, substituted or additional securities or other property pursuant to an adjustment described in Section 11.3) for each Restricted Stock Unit then becoming vested or otherwise to be settled on such date, subject to the withholding of applicable taxes, provided that Restricted Stock Units may be settled in cash, shares of Stock, or a combination thereof as determined by the Committee and set forth in the Award Agreement. Notwithstanding the foregoing, if permitted by the Committee and set forth in the Award Agreement and subject to the restrictions of Section 409A of the Code, the Participant may elect in accordance with terms specified in the Award Agreement to defer receipt of all or any portion of the shares of Stock or other property otherwise issuable to the Participant pursuant to this Section.

12. **Deferred Compensation Awards .**

12.1 **Establishment of Deferred Compensation Award Programs.** This Section 12 shall not be effective unless and until the Committee determines to establish a program pursuant to this Section. The Committee, in its discretion and upon such terms and conditions as it may determine, may establish one or more programs pursuant to the Plan under which:

(a) Subject to the restrictions of Section 409A of the Code, Participants designated by the Committee who are Insiders or otherwise among a select group of management or highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to reduce such Participant's compensation otherwise payable in cash (subject to any minimum or maximum reductions imposed by the Committee) and to be granted automatically at such time or times as specified by the Committee one or more Awards of Stock Units with respect to such numbers of shares of Stock as determined in accordance with the rules of the program established by the Committee and having such other terms and conditions as established by the Committee.

(b) Subject to the restrictions of Section 409A of the Code, Participants designated by the Committee who are Insiders or otherwise among a select group of management or highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to be granted automatically an Award of Stock Units with respect to such number of shares of Stock and upon such other terms and conditions as established by the Committee in lieu of cash or shares of Stock otherwise issuable to such Participant upon the settlement of a Performance Award or Performance Unit.

12.2 **Terms and Conditions of Deferred Compensation Awards.** Deferred Compensation Awards granted pursuant to this Section 12 shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No such Deferred Compensation Award or purported Deferred Compensation Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Deferred Compensation Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

(a) ***Vesting Conditions*** . Deferred Compensation Awards shall or shall not be subject to vesting conditions, as determined by the Committee.

(b) ***Terms and Conditions of Stock Units*** .

(i) **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the applicable Award Agreement that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Stock Units held by such Participant are settled. Such Dividend Equivalents shall be paid by crediting the Participant with additional whole and/or fractional Stock Units as of the date of payment of such cash dividends on Stock. The method of determining the number of additional Stock Units to be so credited shall be specified by the Committee and set forth in the Award Agreement. Such additional Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Stock Units originally subject to the Stock Unit Award. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2, appropriate adjustments shall be made in the Participant's Stock Unit Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Award.

(ii) **Settlement of Stock Unit Awards.** A Participant electing to receive an Award of Stock Units pursuant to this Section 12, shall specify at the time of such election a settlement date with respect to such Award in accordance with rules established by the Committee. Except as otherwise set forth in the applicable Award Agreement, the Company shall issue to the Participant upon the earlier of the settlement date elected by the Participant or the date of the Participant's Separation from Service, a number of whole shares of Stock equal to the number of whole Stock Units subject to the Stock Unit Award. The Participant shall not be required to pay any additional consideration (other than applicable tax withholding) to acquire such shares. Any fractional Stock Unit subject to the Stock Unit Award shall be settled by the Company by payment in cash of an amount equal to the Fair Market Value as of the payment date of such fractional share.

13. **Other Stock-Based Awards** .

In addition to the Awards set forth in Sections 6 through 12 above, the Committee, in its sole discretion, may carry out the purpose of this Plan by awarding Stock-Based Awards as it determines to be in the best interests of the Company and subject to such other terms and conditions as it deems necessary and appropriate. Such awards may be evidenced by Award Agreements in such form as the Committee shall from time to time establish.

14. **Change in Control .**

14.1 **Effect of Change in Control .** Except as set forth in an applicable Award Agreement, in the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror "), may, without the consent of any Participant, either assume or continue the Company's rights and obligations under outstanding Awards or substitute for such Awards substantially equivalent Awards covering the Acquiror's stock. Except as set forth in an applicable Award Agreement, any such Awards which are neither assumed, continued, or substituted by the Acquiror in connection with the Change in Control nor exercised (if applicable) as of the Change in Control shall, contingent on the Change in Control, become fully vested, and Options and SARs become exercisable immediately prior to the Change in Control. Except as set forth in an applicable Award Agreement, Awards which are assumed or continued in connection with a Change in Control shall be subject to such additional accelerated vesting and/or exercisability, or lapse of restrictions in connection with the Participant's termination of Service in connection with the Change in Control as the Committee or Board may determine, if any.

14.2 **Non-employee Director Awards** . Notwithstanding the foregoing, Non-employee Director Awards shall be subject to the terms of Section 7, and not this Section 14.

15. **Compliance with Securities Law .**

The grant of Awards and the issuance of shares of Stock pursuant to any Award shall be subject to compliance with all applicable requirements of federal, state and foreign law with respect to such securities and the requirements of any stock exchange or market system upon which the Stock may then be listed. In addition, no Award may be exercised or shares issued pursuant to an Award unless (a) a registration statement under the Securities Act shall at the time of such exercise or issuance be in effect with respect to the shares issuable pursuant to the Award or (b) in the opinion of legal counsel to the Company, the shares issuable pursuant to the Award may be issued in accordance with the terms of an applicable exemption from the registration requirements of the Securities Act. The inability of the Company to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Company's legal counsel to be necessary to the lawful issuance and sale of any shares hereunder shall relieve the Company of any liability in respect of the failure to issue or sell such shares as to which such requisite authority shall not have been obtained. As a condition to issuance of any Stock, the Company may require the Participant to satisfy any qualifications that may be necessary or appropriate, to evidence compliance with any applicable law or regulation and to make any representation or warranty with respect thereto as may be requested by the Company.

16. **Tax Withholding .**

16.1 **Tax Withholding in General.** The Company shall have the right to deduct from any and all payments made under the Plan, or to require the Participant, through payroll withholding, cash payment or otherwise, including by means of a Cashless Exercise or Net Exercise of an Option, to make adequate provision for, the federal, state, local and foreign taxes, if any, required by law to be withheld by the Participating Company Group with respect to an Award or the shares acquired pursuant thereto. The Company shall have no obligation to deliver shares of Stock, to release shares of Stock from an escrow established pursuant to an Award Agreement, or to make any payment in cash under the Plan unless the Participating Company Group's tax withholding obligations have been satisfied by the Participant.

16.2 **Withholding in Shares.** The Company shall have the right, but not the obligation, to deduct from the shares of Stock issuable to a Participant upon the exercise or settlement of an Award, or to accept from the Participant the tender of, a number of whole shares of Stock having a Fair Market Value, as determined by the Company, equal to all or any part of the tax withholding obligations of the Participating Company Group. Notwithstanding the foregoing, the Fair Market Value of any shares of Stock withheld or tendered to satisfy any such tax withholding obligations shall not exceed the amount determined by the applicable minimum statutory withholding rates to the extent required to avoid adverse accounting or other consequences to the Company or Participant.

17. **Amendment or Termination of Plan .**

The Board or the Committee may amend, suspend or terminate the Plan at any time. However, without the approval of the Company's shareholders, there shall be (a) no increase in the maximum aggregate number of shares of Stock that may be issued under the Plan (except by operation of the provisions of Section 4.2), (b) no change in the class of persons eligible to receive Incentive Stock Options, (c) no amendment to Section 5.4(b) or 5.4(c), and (d) no other amendment of the Plan that would require approval of the Company's shareholders under any applicable law, regulation or rule. Notwithstanding the foregoing, only the Board may amend Section 7 and may do so without the approval of the Company's shareholders. No amendment, suspension or termination of the Plan shall affect any then outstanding Award unless expressly provided by the Board or the Committee. In any event, no amendment, suspension or termination of the Plan may adversely affect any then outstanding Award without the consent of the Participant unless necessary to comply with any applicable law, regulation or rule.

18. **Miscellaneous Provisions .**

18.1 **Repurchase Rights .** Shares issued under the Plan may be subject to one or more repurchase options, or other conditions and restrictions as determined by the Committee in its discretion at the time the Award is granted. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

18.2 **Provision of Information.** Each Participant shall be given access to information concerning the Company equivalent to that information generally made available to the Company's common shareholders.

18.3 **Rights as Employee, Consultant or Director.** No person, even though eligible pursuant to Section 5, shall have a right to be selected as a Participant, or, having been so selected, to be selected again as a Participant. Nothing in the Plan or any Award granted under the Plan shall confer on any Participant a right to remain an Employee, Consultant or Director or interfere with or limit in any way any right of a Participating Company to terminate the Participant's Service at any time. To the extent that an Employee of a Participating Company other than the Company receives an Award under the Plan, that Award shall in no event be understood or interpreted to mean that the Company is the Employee's employer or that the Employee has an employment relationship with the Company. A Participant's rights, if any, in respect of or in connection with any Award is derived solely from the discretionary decision of the Company to permit the individual to participate in the Plan and to benefit from a discretionary Award. By accepting an Award under the Plan, a Participant expressly acknowledges that there is no obligation on the part of the Company to continue the Plan and/or grant any additional Awards. Any Award granted hereunder is not intended to be compensation of a continuing or recurring nature, or part of a Participant's normal or expected compensation, and in no way represents any portion of a Participant's salary, compensation, or other remuneration for purposes of pension benefits, severance, redundancy, resignation or any other purpose. The Company and its Parent Corporations and Subsidiary Corporations and Affiliates reserve the right to terminate the Service of any person at any time, and for any reason, subject to applicable laws and such person's written employee agreement (if any), and such terminated person shall be deemed irrevocably to have waived any claim to damages or specific performance for breach of contract or dismissal, compensation for loss of office, tort or otherwise with respect to the Plan or any outstanding Award that is forfeited and/or is terminated by its terms or to any future Award.

18.4 **Rights as a Shareholder.** A Participant shall have no rights as a shareholder with respect to any shares covered by an Award until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). No adjustment shall be made for dividends, distributions or other rights for which the record date is prior to the date such shares are issued, except as provided in another provision of the Plan.

18.5 **Fractional Shares.** The Company shall not be required to issue fractional shares upon the exercise or settlement of any Award.

18.6 **Severability** . If any one or more of the provisions (or any part thereof) of this Plan shall be held invalid, illegal or unenforceable in any respect, such provision shall be modified so as to make it valid, legal and enforceable, and the validity, legality and enforceability of the remaining provisions (or any part thereof) of the Plan shall not in any way be affected or impaired thereby.

18.7 **Beneficiary Designation.** Subject to local laws and procedures, each Participant may file with the Company a written designation of a beneficiary who is to receive any benefit under the Plan to which the Participant is entitled in the event of such Participant's death before he or she receives any or all of such benefit. Each designation will revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. If a married Participant designates a beneficiary other than the Participant's spouse, the effectiveness of such designation may be subject to the consent of the Participant's spouse. If a Participant dies without an effective designation of a beneficiary who is living at the time of the Participant's death, the Company will pay any remaining unpaid benefits to the Participant's legal representative.

18.8 **Unfunded Obligation.** Participants shall have the status of general unsecured creditors of the Company. Any amounts payable to Participants pursuant to the Plan shall be unfunded and unsecured obligations for all purposes, including, without limitation, Title I of the Employee Retirement Income Security Act of 1974. No Participating Company shall be required to segregate any monies from its general funds, or to create any trusts, or establish any special accounts with respect to such obligations. The Company shall retain at all times beneficial ownership of any investments, including trust investments, which the Company may make to fulfill its payment obligations hereunder. Any investments or the creation or maintenance of any trust or any Participant account shall not create or constitute a trust or fiduciary relationship between the Committee or any Participating Company and a Participant, or otherwise create any vested or beneficial interest in any Participant or the Participant's creditors in any assets of any Participating Company. The Participants shall have no claim against any Participating Company for any changes in the value of any assets which may be invested or reinvested by the Company with respect to the Plan. Each Participating Company shall be responsible for making benefit payments pursuant to the Plan on behalf of its Participants or for reimbursing the Company for the cost of such payments, as determined by the Company in its sole discretion. In the event the respective Participating Company fails to make such payment or reimbursement, a Participant's (or other individual's) sole recourse shall be against the respective Participating Company, and not against the Company. A Participant's acceptance of an Award pursuant to the Plan shall constitute agreement with this provision.

18.9 **Choice of Law.** Except to the extent governed by applicable federal law, the validity, interpretation, construction and performance of the Plan and each Award Agreement shall be governed by the laws of the State of California, without regard to its conflict of law rules.

18.10 **Section 409A of the Code.** Notwithstanding anything to the contrary in the Plan, to the extent (i) any Award payable in connection with a Participant's Separation from Service constitutes deferred compensation subject to (and not exempt from) Section 409A of the Code and (ii) the Participant is deemed at the time of such separation to be a "specified employee" under Section 409A of the Code and the Treasury regulations thereunder, then payment shall not be made or commence until the earlier of (i) six (6)-months after such Separation from Service or (ii) the date of the Participant's death following such Separation from Service; provided, however, that such delay shall only be effected to the extent required to avoid adverse tax treatment to the Participant, including (without limitation) the additional twenty percent (20%) tax for which the Participant would otherwise be liable under Section 409A(a)(1)(B) of the Code in the absence of such delay. Upon the expiration of the applicable delay period, any payment which would have otherwise been paid during that period (whether in a single sum or in installments) in the absence of this paragraph shall be paid to the Participant or the Participant's beneficiary in one lump sum on the first business day immediately following such delay and any undelayed payments will be paid in accordance with their normal terms.

18.11 **Restrictions on Transfer** . No Award and no shares of Stock that have not been issued or as to which any applicable restriction, performance or deferral period has not lapsed, may be sold, assigned, transferred, pledged or otherwise encumbered, other than by will or the laws of decent and distribution, and such Award may be exercised during the life of the Participant only by the Participant or the Participant's guardian or legal representative. Notwithstanding the foregoing, to the extent permitted by the Committee, in its discretion, and set forth in the applicable Award Agreement, an Award shall be assignable or transferrable to a "family member" or other permitted transferee to the extent covered under Form S-8 Registration Statement under the Securities Act.

PLAN HISTORY AND NOTES TO COMPANY

| | |
|---|---|
| February 19, 2014 | Board adopts Plan with a reserve of 17 million shares, less one share for every one share of Stock covered by an award granted under the Prior Plan after December 31, 2013 and prior to the Effective Date. |
| May 12, 2014 | Shareholders approve Plan. Plan Effective Date |
| January 1, 2015 | Non-employee director awards amended to:<br>Increase the value of annual awards to $120,000 from $105,000.<br><br>Change the vesting date to the earlier of the anniversary of the grant date or the last day of the director's elected term. |
| January 1, 2016 | The value of annual LTIP awards to non-employee directors increased to $140,000 from $120,000. |
| February 15, 2017 | CEO no longer required to be PG&E Corporation director in order to make certain types of LTIP awards.<br>Expand deferral options for non-employee director awards. |
| January 1, 2018 | The value of the annual LTIP awards to the non-employee director serving as PG&E Corporation's non-executive Chair of the Board increased to $220,000 from $140,000. |

EXHIBIT 10.55

# PG&E Corporation

# 2014 Long-Term Incentive Plan

# PG&E Corporation
# 2014 Long-Term Incentive Plan

(As adopted effective May 12, 2014, and as amended effective February 15, 2017)

1. **Establishment, Purpose and Term of Plan .**

1.1 **Establishment .** The PG&E Corporation 2014 Long-Term Incentive Plan (the " ***Plan*** " ) is hereby established effective as of the date approved by the shareholders of the Company (the "Effective Date"). This Plan replaces the PG&E Corporation 2006 Long-Term Incentive Plan.

1.2 **Purpose .** The purpose of the Plan is to advance the interests of the Participating Company Group and its shareholders by providing an incentive to attract and retain the best qualified personnel to perform services for the Participating Company Group, by motivating such persons to contribute to the growth and profitability of the Participating Company Group, by aligning their interests with interests of the Company's shareholders, and by rewarding such persons for their services by tying a significant portion of their total compensation package to the success of the Company. The Plan seeks to achieve this purpose by providing for Awards in the form of Options, Stock Appreciation Rights, Restricted Stock Awards, Performance Shares, Performance Units, Restricted Stock Units, Deferred Compensation Awards and other Stock-Based Awards as described below.

1.3 **Term of Plan.** The Plan shall continue in effect until the earlier of its termination by the Board or the date on which no Awards remain outstanding under the Plan. However, the term during which all Awards shall be granted, if at all, shall be within ten (10) years from the Effective Date. Moreover, Incentive Stock Options shall not be granted later than February 19, 2024 (ten (10) years from the date on which the Plan was adopted by the Board).

2. **Definitions and Construction .**

2.1 **Definitions.** Whenever used herein, the following terms shall have their respective meanings set forth below:

(a) " ***Affiliate*** " means (i) an entity, other than a Parent Corporation, that directly, or indirectly through one or more intermediary entities, controls the Company or (ii) an entity, other than a Subsidiary Corporation, that is controlled by the Company directly, or indirectly through one or more intermediary entities. For this purpose, the term "control" (including the term "controlled by") means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of the relevant entity, whether through the ownership of voting securities, by contract or otherwise; or shall have such other meaning assigned such term for the purposes of registration on Form S-8 under the Securities Act.

(b) " ***Award*** " means any Option, SAR, Restricted Stock Award, Performance Share, Performance Unit, Restricted Stock Unit or Deferred Compensation Award or other Stock-Based Award granted under the Plan.

(c) " ***Award Agreement*** " means a written agreement between the Company and a Participant setting forth the terms, conditions and restrictions of the Award granted to the Participant (which may also be in electronic form).

(d) " ***Board*** " means the Board of Directors of the Company.

(e) " ***Change in Control*** " means, unless otherwise defined by the Participant's Award Agreement or contract of employment or service, the occurrence of any of the following:

(i) any "person" (as such term is used in Sections 13(d) and 14(d) of the Exchange Act, but excluding any benefit plan for Employees or any trustee, agent or other fiduciary for any such plan acting in such person's capacity as such fiduciary), directly or indirectly, becomes the "beneficial owner" (as defined in Rule 13d-3 promulgated under the Exchange Act), of stock of the Company representing thirty percent (30%) or more of the combined voting power of the Company's then outstanding voting stock; or

(ii) during any two consecutive years, individuals who at the beginning of such period constitute the Board cease for any reason to constitute at least a majority of the Board, unless the election, or the nomination for election by the shareholders of the Company, of each new Director was approved by a vote of at least two-thirds (2/3) of the Directors then still in office (1) who were Directors at the beginning of the period or (2) whose election or nomination was previously so approved; or

(iii) the consummation of any consolidation or merger of the Company other than a merger or consolidation which would result in the holders of the voting stock of the Company outstanding immediately prior thereto continuing to directly or indirectly hold at least seventy percent (70%) of the Combined Voting Power of the Company, the surviving entity in the merger or consolidation or the parent of such surviving entity outstanding immediately after the merger or consolidation; or

(iv) (1) the consummation of any sale, lease, exchange or other transfer (in one or a series of related transactions) of all or substantially all of the assets of the Company, or (2) the approval of the Shareholders of the Company of a plan of liquidation or dissolution of the Company.

For purposes of paragraph (iii), the term ***"Combined Voting Power"*** shall mean the combined voting power of the Company's or other relevant entity's then outstanding voting stock.

(f) " ***Code*** " means the Internal Revenue Code of 1986, as amended, and any applicable regulations promulgated thereunder.

(g) " ***Committee*** " means the Compensation Committee or other committee of the Board duly appointed to administer the Plan and having such powers as shall be specified by the Board. If no committee of the Board has been appointed to administer the Plan, the Board shall exercise all of the powers of the Committee granted herein, and, in any event, the Board may in its discretion exercise any or all of such powers.

(h) ***" Company "*** means PG&E Corporation, a California corporation, or any successor corporation thereto.

(i) ***" Consultant "*** means a person engaged to provide consulting or advisory services (other than as an Employee or a member of the Board) to a Participating Company, provided that the identity of such person, the nature of such services or the entity to which such services are provided would not preclude the Company from offering or selling securities to such person pursuant to the Plan in reliance on registration on a Form S-8 Registration Statement under the Securities Act.

(j) ***" Deferred Compensation Award "*** means an award of Stock Units granted to a Participant pursuant to Section 12 of the Plan.

(k) ***" Director "*** means a member of the Board.

(l) ***" Disability "*** means the permanent and total disability of the Participant, within the meaning of Section 22(e)(3) of the Code, except as otherwise set forth in the Plan or an Award Agreement.

(m) ***" Dividend Equivalent "*** means a credit, made at the discretion of the Committee or as otherwise provided by the Plan, to the account of a Participant in an amount equal to the cash dividends paid on one share of Stock for each share of Stock represented by an Award held by such Participant.

(n) ***" Employee "*** means any person treated as an employee (including an Officer or a member of the Board who is also treated as an employee) in the records of a Participating Company and, with respect to any Incentive Stock Option granted to such person, who is an employee for purposes of Section 422 of the Code; provided, however, that neither service as a member of the Board nor payment of a director's fee shall be sufficient to constitute employment for purposes of the Plan. The Company shall determine in good faith and in the exercise of its discretion whether an individual has become or has ceased to be an Employee and the effective date of such individual's employment or termination of employment, as the case may be. For purposes of an individual's rights, if any, under the Plan as of the time of the Company's determination, all such determinations by the Company shall be final, binding and conclusive, notwithstanding that the Company or any court of law or governmental agency subsequently makes a contrary determination.

(o) ***" Exchange Act "*** means the Securities Exchange Act of 1934, as amended.

(p) ***" Fair Market Value "*** means, as of any date, the value of a share of Stock or other property as determined by the Committee, in its discretion, or by the Company, in its discretion, if such determination is expressly allocated to the Company herein, subject to the following:

(i) Except as otherwise determined by the Committee, if, on such date, the Stock is listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be the closing price of a share of Stock as quoted on the New York Stock Exchange or such other national or regional securities exchange or market system constituting the primary market for the Stock, as reported in *The Wall Street Journal* or such other source as the Company deems reliable. If the relevant date does not fall on a day on which the Stock has traded on such securities exchange or market system, the date on which the Fair Market Value shall be established shall be the last day on which the Stock was so traded prior to the relevant date, or such other appropriate day as shall be determined by the Committee, in its discretion.

(ii) Notwithstanding the foregoing, the Committee may, in its discretion, determine the Fair Market Value on the basis of the opening, closing, high, low or average sale price of a share of Stock or the actual sale price of a share of Stock received by a Participant, on such date, the preceding trading day, the next succeeding trading day or an average determined over a period of trading days. The Committee may vary its method of determination of the Fair Market Value as provided in this Section for different purposes under the Plan.

(iii) If, on such date, the Stock is not listed on a national or regional securities exchange or market system, the Fair Market Value of a share of Stock shall be as determined by the Committee in good faith without regard to any restriction other than a restriction which, by its terms, will never lapse.

(q) ***" Incentive Stock Option "*** means an Option intended to be (as set forth in the Award Agreement) and which qualifies as an incentive stock option within the meaning of Section 422(b) of the Code.

(r) ***" Insider "*** means an Officer, a Director or any other person whose transactions in Stock are subject to Section 16 of the Exchange Act.

(s) ***"Net-Exercise"*** means a procedure by which the Participant will be issued a number of shares of Stock determined in accordance with the following formula:

X = Y(A-B)/A, where
X = the number of shares of Stock to be issued to the Participant upon exercise of the Option;
Y = the total number of shares with respect to which the Participant has elected to exercise the Option;
A = the Fair Market Value of one (1) share of Stock;
B = the exercise price per share (as defined in the Participant's Award Agreement).

(t) ***" Non-employee Director "*** means a Director who is not an Employee.

(u) ***" Non-employee Director Award "*** means an Award granted to a Non-employee Director pursuant to Section 7 of the Plan.

(v) ***" Nonstatutory Stock Option "*** means an Option not intended to be (as set forth in the Award Agreement) an incentive stock option within the meaning of Section 422(b) of the Code.

(w) ***"Officer "*** means any person designated by the Board as an officer of the Company.

(x) ***" Option "*** means the right to purchase Stock at a stated price for a specified period of time granted to a Participant pursuant to Section 6 or Section 7 of the Plan. An Option may be either an Incentive Stock Option or a Nonstatutory Stock Option.

(y) ***"Option Expiration Date"*** means the date of expiration of the Option's term as set forth in the Award Agreement.

(z) ***" Parent Corporation "*** means any present or future "parent corporation" of the Company in an unbroken chain of corporations ending with the Company in which each of the corporations other than the Company owns stock possessing 50% or more of the total combined voting power of all classes of stock in one of the other corporations in such chain.

(aa) ***" Participant "*** means any eligible person who has been granted one or more Awards.

(bb) ***" Participating Company "*** means the Company or any Parent Corporation, Subsidiary Corporation or Affiliate.

(cc) ***" Participating Company Group "*** means, at any point in time, all entities collectively which are then Participating Companies.

(dd) ***" Performance Award "*** means an Award of Performance Shares or Performance Units.

(ee) ***" Performance Award Formula "*** means, for any Performance Award, a formula or table established by the Committee pursuant to Section 10.3 of the Plan which provides the basis for computing the value of a Performance Award at one or more levels of attainment of the applicable Performance Goal(s) measured as of the end of the applicable Performance Period.

(ff) ***" Performance Goal "*** means a performance goal established by the Committee pursuant to Section 10.3 of the Plan.

(gg) ***" Performance Period "*** means a period established by the Committee pursuant to Section 10.3 of the Plan at the end of which one or more Performance Goals are to be measured.

(hh) ***" Performance Share "*** means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Share, as determined by the Committee, based on performance.

(ii) ***" Performance Unit "*** means a bookkeeping entry representing a right granted to a Participant pursuant to Section 10 of the Plan to receive a payment equal to the value of a Performance Unit, as determined by the Committee, based upon performance.

(jj) ***" Prior Plan "*** means the PG&E Corporation 2006 Long-Term Incentive Plan.

(kk) ***" Restricted Stock Award "*** means an Award of Restricted Stock.

(ll) ***" Restricted Stock Unit"*** or ***" Stock Unit "*** means a bookkeeping entry representing a right granted to a Participant pursuant to Section 11 or Section 12 of the Plan, respectively, to receive a share of Stock or payment equal to the value of a share of Stock on a date determined in accordance with the provisions of Section 11 or Section 12, as applicable, and the Participant's Award Agreement.

(mm) ***" Restriction Period "*** means the period established in accordance with Section 9.4 of the Plan during which shares subject to a Restricted Stock Award are subject to Vesting Conditions.

(nn) ***"Retirement"*** means termination as an Employee with the Participating Company Group at age 55 or older, provided that the Participant was an Employee for at least five consecutive years prior to the date of such termination.

(oo) ***" Rule 16b-3 "*** means Rule 16b-3 under the Exchange Act, as amended from time to time, or any successor rule or regulation.

(pp) ***" SAR "*** or ***" Stock Appreciation Right "*** means a bookkeeping entry representing, for each share of Stock subject to such SAR, a right granted to a Participant pursuant to Section 8 of the Plan to receive payment in any combination of shares of Stock or cash of an amount equal to the excess, if any, of the Fair Market Value of a share of Stock on the date of exercise of the SAR over the exercise price.

(qq) ***" Section 162(m) "*** means Section 162(m) of the Code.

(rr) ***" Section 409A Change in Control "*** means a "change in the ownership or effective control of the corporation, or in the ownership of a substantial portion of the assets of the corporation," within the meaning of Section 409A of the Code, as such definition applies to the Company.

(ss) ***" Securities Act "*** means the Securities Act of 1933, as amended.

(tt) ***" Separation from Service "*** means a Participant's "separation from service," within the meaning of Section 409A of the Internal Revenue Code.

(uu) ***" Service "*** means a Participant's employment or service with the Participating Company Group, whether in the capacity of an Employee, a Director or a Consultant. A Participant's Service shall not be deemed to have terminated merely because of a change in the capacity in which the Participant renders such Service or a change in the Participating Company for which the Participant renders such Service, provided that there is no interruption or termination of the Participant's Service. Furthermore, a Participant's Service shall not be deemed to have terminated if the Participant takes any military leave, sick leave, or other bona fide leave of absence approved by the Company. However, if any such leave taken by a Participant exceeds ninety (90) days, then on the ninety-first (91st) day following the commencement of such leave the Participant's Service shall be deemed terminated and any Incentive Stock Option held by the

Participant shall cease to be treated as an Incentive Stock Option and instead shall be treated thereafter as a Nonstatutory Stock Option commencing on the third (3 rd ) month from such deemed termination, unless the Participant's right to return to Service with the Participating Company Group is guaranteed by statute or contract. Notwithstanding the foregoing, unless otherwise designated by the Company or required by law, a leave of absence shall not be treated as Service for purposes of determining vesting under the Participant's Award Agreement. A Participant's Service shall be deemed to have terminated either upon an actual termination of Service or upon the entity for which the Participant performs Service ceasing to be a Participating Company. Subject to the foregoing, the Company, in its discretion, shall determine whether the Participant's Service has terminated and the effective date of such termination.

(vv) *" Stock "* means the common stock of the Company, as adjusted from time to time in accordance with Section 4.2 of the Plan.

(ww) *" Stock-Based Awards "* means any award that is valued in whole or in part by reference to, or is otherwise based on, the Stock, including dividends on the Stock, but not limited to those Awards described in Sections 6 through 12 of the Plan.

(xx) *" Subsidiary Corporation "* means any present or future "subsidiary corporation" of the Company in an unbroken chain of corporations beginning with the Company in which each of the corporations other than the last corporation owns stock possessing 50% or more of the total combined voting power of all classes of stock in one of the other corporations in such chain.

(yy) " ***Substitute Awards"*** means Awards granted or Shares issued by the Company in assumption of, or in substitution or exchange for, awards previously granted, or the right or obligation to make future awards, in each case by a company acquired by the Company or any Subsidiary Corporation or with which the Company or any Subsidiary Corporation combines.

(zz) *" Ten Percent Owner "* means a Participant who, at the time an Option is granted to the Participant, owns stock possessing more than ten percent (10%) of the total combined voting power of all classes of stock of a Participating Company (other than an Affiliate) within the meaning of Section 422(b)(6) of the Code.

(aaa) *" Vesting Conditions "* mean those conditions established in accordance with Section 9.4 or Section 11.2 of the Plan prior to the satisfaction of which shares subject to a Restricted Stock Award or Restricted Stock Unit Award, respectively, remain subject to forfeiture or a repurchase option in favor of the Company upon the Participant's termination of Service, or other deadline for satisfying such conditions, as applicable.

2.2 **Construction.** Captions and titles contained herein are for convenience only and shall not affect the meaning or interpretation of any provision of the Plan. Except when otherwise indicated by the context, the singular shall include the plural and the plural shall include the singular. Use of the term "or" is not intended to be exclusive, unless the context clearly requires otherwise.

3. **Administration .**

3.1 **Administration by the Committee.** The Plan shall be administered by the Committee. All questions of interpretation of the Plan or of any Award shall be determined by the Committee, and such determinations shall be final and binding upon all persons having an interest in the Plan or such Award.

3.2 **Authority of Officers.** Any Officer shall have the authority to act on behalf of the Company with respect to any matter, right, obligation, determination or election which is the responsibility of or which is allocated to the Company herein, provided the Officer has apparent authority with respect to such matter, right, obligation, determination or election. In addition, to the extent specified in a resolution adopted by the Board, the Chief Executive Officer of the Company shall have the authority to grant Awards to an Employee who is not an Insider and who is receiving a salary below the level which requires approval by the Committee; provided that the terms of such Awards conform to guidelines established by the Committee.

3.3 **Administration with Respect to Insiders.** With respect to participation by Insiders in the Plan, at any time that any class of equity security of the Company is registered pursuant to Section 12 of the Exchange Act, the Plan shall be administered in compliance with the requirements, if any, of Rule 16b-3.

3.4 **Committee Complying with Section 162(m).** While the Company is a "publicly held corporation" within the meaning of Section 162(m), the Board may establish a Committee of "outside directors" within the meaning of Section 162(m) to approve the grant of any Award which might reasonably be anticipated to result in the payment of employee remuneration that would otherwise exceed the limit on employee remuneration deductible for income tax purposes pursuant to Section 162(m).

3.5 **Powers of the Committee .** In addition to any other powers set forth in the Plan and subject to the provisions of the Plan, the Committee shall have the full and final power and authority, in its discretion:

(a) to determine the persons to whom, and the time or times at which, Awards shall be granted and the number of shares of Stock or units to be subject to each Award based on the recommendation of the Chief Executive Officer of the Company (except that Awards to the Chief Executive Officer shall be based on the recommendation of the independent members of the Board in compliance with applicable stock exchange rules, Non-employee Director Awards shall be granted automatically pursuant to Section 7 of the Plan, and other Awards to Non-employee Directors shall be approved by the Board);

(b) to determine the type of Award granted and to designate Options as Incentive Stock Options or Nonstatutory Stock Options;

(c) to determine the Fair Market Value of shares of Stock or other property;

(d) to determine the terms, conditions and restrictions applicable to each Award (which need not be identical) and any shares acquired pursuant thereto, including, without limitation, (i) the exercise or purchase price of shares purchased pursuant to any Award, (ii) the method of payment for shares purchased pursuant to any Award, (iii) the method for satisfaction of any tax withholding obligation arising in connection with any Award, including by the withholding or delivery of shares of Stock, (iv) the timing, terms and conditions of the exercisability or vesting of any Award or any shares acquired pursuant thereto, (v) the Performance Award Formula and Performance Goals applicable to any Award and the extent to which such Performance Goals have been attained, (vi) the time of the expiration of any Award, (vii) the effect of the Participant's termination of Service on any of the foregoing, and (viii) all other terms, conditions and restrictions applicable to any Award or shares acquired pursuant thereto not inconsistent with the terms of the Plan;

(e) to determine whether an Award will be settled in shares of Stock, cash, or in any combination thereof;

(f) to approve one or more forms of Award Agreement;

(g) to amend, modify, extend, cancel or renew any Award or to waive any restrictions or conditions applicable to any Award or any shares acquired pursuant thereto, subject, in the case of an adversely affected Award, to the affected Participant's consent unless necessary to comply with any applicable law, regulation, or rule;

(h) to accelerate, continue, extend or defer the exercisability or vesting of any Award or any shares acquired pursuant thereto, including with respect to the period following a Participant's termination of Service;

(i) without the consent of the affected Participant and notwithstanding the provisions of any Award Agreement to the contrary, to unilaterally substitute at any time a Stock Appreciation Right providing for settlement solely in shares of Stock in place of any outstanding Option, provided that such Stock Appreciation Right covers the same number of shares of Stock and provides for the same exercise price (subject in each case to adjustment in accordance with Section 4.2) as the replaced Option and otherwise provides substantially equivalent terms and conditions as the replaced Option, as determined by the Committee, and subject to limitations set forth in Section 3.6;

(j) to prescribe, amend or rescind rules, guidelines and policies relating to the Plan, or to adopt sub-plans or supplements to, or alternative versions of, the Plan, including, without limitation, as the Committee deems necessary or desirable to comply with the laws or regulations of or to accommodate the tax policy, accounting principles or custom of, foreign jurisdictions whose citizens may be granted Awards;

(k) to correct any defect, supply any omission or reconcile any inconsistency in the Plan or any Award Agreement and to make all other determinations and take such other actions with respect to the Plan or any Award as the Committee may deem advisable to the extent not inconsistent with the provisions of the Plan or applicable law; and

(l) to delegate to the Chief Executive Officer or the Senior Vice President of Human Resources the authority with respect to ministerial matters regarding the Plan and Awards made under the Plan.

3.6 **Option or SAR Repricing/Buyout.** Notwithstanding anything to the contrary set forth in the Plan, without the affirmative vote of holders of a majority of the shares of Stock cast in person or by proxy at a meeting of the shareholders of the Company at which a quorum representing a majority of all outstanding shares of Stock is present or represented by proxy, the Company shall not approve a program providing for any of the following: (a) the cancellation of outstanding Options or SARs and the grant in substitution therefore of new Options or SARs having a lower exercise price, another Award, cash or a combination thereof (other than in connection with a Change in Control), (b) the amendment of outstanding Options or SARs to reduce the exercise price thereof, (c) the purchase of outstanding unexercised Options or SARs by the Company whether by cash payment or otherwise, or (d) any other action with respect to an Option or SAR that would be treated as a repricing under the rules and regulations of the principal U.S. national securities exchanges on which the Stock is listed. This paragraph shall not be construed to apply to "issuing or assuming a stock option in a transaction to which section 424(a) applies," within the meaning of Section 424 of the Code. For the avoidance of doubt, this Section 3.6 shall not preclude any action taken without shareholder approval that is described in Section 4.2.

3.7 **Indemnification.** In addition to such other rights of indemnification as they may have as members of the Board or the Committee or as officers or employees of the Participating Company Group, members of the Board or the Committee and any officers or employees of the Participating Company Group to whom authority to act for the Board, the Committee or the Company is delegated shall be indemnified by the Company against all reasonable expenses, including attorneys' fees, actually and necessarily incurred in connection with the defense of any action, suit or proceeding, or in connection with any appeal therein, to which they or any of them may be a party by reason of any action taken or failure to act under or in connection with the Plan, or any right granted hereunder, and against all amounts paid by them in settlement thereof (provided such settlement is approved by independent legal counsel selected by the Company) or paid by them in satisfaction of a judgment in any such action, suit or proceeding, except in relation to matters as to which it shall be adjudged in such action, suit or proceeding that such person is liable for gross negligence, bad faith or intentional misconduct in duties; provided, however, that within sixty (60) days after the institution of such action, suit or proceeding, such person shall offer to the Company, in writing, the opportunity at its own expense to handle and defend the same.

4. **<u>Shares Subject to Plan</u>.**

4.1 **Maximum Number of Shares Issuable.** Subject to adjustment as provided in Section 4.2, the maximum aggregate number of shares of Stock that may be issued under the Plan shall be seventeen million (17,000,000) less one share for every one share of Stock covered by an award granted under the Prior Plan after December 31, 2013 and prior to the Effective Date. After the Effective Date, no awards may be granted under the Prior Plan. Shares of Stock issued hereunder shall consist of authorized but unissued or reacquired shares of Stock or any combination thereof. If (i) an outstanding Award for any reason expires or is terminated or canceled without having been exercised or settled in full, or if shares of Stock acquired pursuant to an Award subject to forfeiture or repurchase are forfeited or repurchased by the Company, the shares of Stock allocable to the terminated portion of such Award or such forfeited or repurchased shares of Stock shall again be available for issuance under the Plan; or (ii) after December 31, 2013, an outstanding award under the Prior Plan (whenever granted) for any reason expires or is terminated or canceled without having been exercised or settled in full, or if shares of stock acquired pursuant to an award under the Prior Plan subject to forfeiture or repurchase are forfeited or repurchased by the Company, the shares of stock allocable to the terminated portion of such award or such forfeited or repurchased shares or stock shall again be available for issuance under the Plan (as of December 31, 2013 there were 6,194,819 shares of stock subject to outstanding awards under the Prior Plan). Shares of Stock shall not be deemed to have been issued pursuant to the Plan (and shall again be available for issuance under the Plan) with respect to any portion of an Award (or, after December 31, 2013, an award under the Prior Plan) that is settled in cash (other than in the case of Options or SARs, in which case shares of Stock having a Fair Market Value equal to the cash delivered shall be deemed issued pursuant to the Plan). Upon the exercise of an SAR (or, after December 31, 2013, exercise of an SAR that was granted under the Prior Plan), the gross number of shares for which the SAR is exercised shall be deemed issued and shall not again be available for issuance under the Plan. In the event that (i) any Option or other Award granted hereunder is exercised through the tendering of shares of Stock (either actually or by attestation) or by the withholding of shares by the Company, or (ii) withholding tax liabilities arising from such Award are satisfied by the tendering of shares of Stock (either actually or by attestation) or by the withholding of shares by the Company, then in each such case (other than in the case of such shares tendered or withheld in connection with the exercise of Options or SARs) the shares of Stock so tendered or withheld shall be added to the shares available for grant under the Plan on a one-for-one basis. In the event that after December 31, 2013, (i) any option or award under the Prior Plan is exercised through the tendering of shares (either actually or by attestation) or by the withholding of shares by the Company, or (ii) withholding tax liabilities arising from such options or awards are satisfied by the tendering of shares (either actually or by attestation) or by the withholding of shares by the Company, then in each such case (other than in the case of such shares tendered or withheld in connection with the exercise of Options or SARs) the shares so tendered or withheld shall be added to the shares available for grant under the Plan on a one-for-one basis.

4.2 **Adjustments for Changes in Capital Structure .** Subject to any required action by the shareholders of the Company, Section 409A of the Code and Section 162(m) of the Code for Awards intended to comply with the "qualified performance-based compensation" exception thereunder, in the event of any change in the Stock effected without receipt of consideration by the Company, whether through merger, consolidation, reorganization, reincorporation, recapitalization, reclassification, stock dividend, stock split, reverse stock split, split-up, split-off, spin-off, combination of shares, exchange of shares, or similar change in the capital structure of the Company, or in the event of payment of a dividend or distribution to the shareholders of the Company in a form other than Stock (excepting normal cash dividends) that has a material effect on the Fair Market Value of shares of Stock, appropriate adjustments shall be made in the number and kind of shares subject to the Plan and to any outstanding Awards, in the Award limits set forth in Section 5.4 , and in the exercise or purchase price per share under any outstanding Award in order to prevent dilution or enlargement of Participants' rights under the Plan. For purposes of the foregoing, conversion of any convertible securities of the Company shall not be treated as "effected without receipt of consideration by the Company." Any fractional share resulting from an adjustment pursuant to this Section 4.2 shall be rounded down to the nearest whole number. The Committee in its sole discretion, may also make such adjustments in the terms of any Award to reflect, or related to, such changes in the capital structure of the Company or distributions as it deems appropriate, including modification of Performance Goals, Performance Award Formulas and Performance Periods, subject to Section 162(m) of the Code for Awards intended to qualify as "performance-based compensation" thereunder. The adjustments determined by the Committee pursuant to this Section 4.2 shall be final, binding and conclusive.

4.3 **Substitute Awards** . To the extent permitted under the rules of the applicable stock exchange on which the Stock is listed, Substitute Awards shall not reduce the shares of Stock authorized for grant under the Plan, nor shall Shares subject to a Substitute Award be added to the shares of Stock available for Awards under the Plan as provided above. Additionally, subject to the rules of the applicable stock exchange on which the Stock is listed, in the event that a company acquired by the Company or any Subsidiary Corporation or with which the Company or any Subsidiary Corporation combines has shares available under a pre-existing plan approved by shareholders and not adopted in contemplation of such acquisition or combination, the shares available for grant pursuant to the terms of such pre-existing plan (as adjusted, to the extent appropriate, using the exchange ratio or other adjustment or valuation ratio or formula used in such acquisition or combination to determine the consideration payable to the holders of common stock of the entities party to such acquisition or combination) may be used for Awards under the Plan and shall not reduce the shares authorized for grant under the Plan (and shares subject to such Awards shall not be added to the shares available for Awards under the Plan as provided in the paragraphs above); provided that Awards using such available shares shall not be made after the date awards or grants could have been made under the terms of the pre-existing plan, absent the acquisition or combination, and shall only be made to individuals who were not Employees or Directors prior to such acquisition or combination.

5. **<u>Eligibility and Award Limitations</u> .**

5.1 **Persons Eligible for Awards.** Awards may be granted only to Employees, Consultants and Directors (including Non-employee Directors). For purposes of the foregoing sentence, "Employees," "Consultants" and "Directors" shall include prospective Employees, prospective Consultants and prospective Directors to whom Awards are granted in connection with written offers of an employment or other service relationship with the Participating Company Group; provided, however, that no Stock subject to any such Award shall vest, become exercisable or be issued prior to the date on which such person commences Service. A Non-employee Director Award may be granted only to a person who, at the time of grant, is a Non-employee Director.

5.2 **Participation.** Awards other than Non-employee Director Awards are granted solely at the discretion of the Committee. Eligible persons may be granted more than one Award. However , eligibility in accordance with this Section shall not entitle any person to be granted an Award, or, having been granted an Award, to be granted an additional Award.

5.3 **Incentive Stock Option Limitations.**

(a) ***Persons Eligible.*** An Incentive Stock Option ("ISO") may be granted only to a person who, on the effective date of grant, is an Employee of the Company, a Parent Corporation or a Subsidiary Corporation (each being an ***" ISO-Qualifying Corporation "*** ). Any person who is not an Employee of an ISO-Qualifying Corporation on the effective date of the grant of an Option to such person may be granted only a Nonstatutory Stock Option. An Incentive Stock Option granted to a prospective Employee upon the condition that such person become an Employee of an ISO-Qualifying Corporation shall be deemed granted effective on the date such person commences Service with an ISO-Qualifying Corporation, with an exercise price determined as of such date in accordance with Section 6.1.

(b) ***Fair Market Value Limitation.*** To the extent that options designated as Incentive Stock Options (granted under all stock option plans of the Participating Company Group, including the Plan) become exercisable by a Participant for the first time during any calendar year for stock having a Fair Market Value greater than One Hundred Thousand Dollars ($100,000), the portion of such options which exceeds such amount shall be treated as Nonstatutory Stock Options. For purposes of this Section, options designated as Incentive Stock Options shall be taken into account in the order in which they were granted, and the Fair Market Value of stock shall be determined as of the time the option with respect to such stock is granted. If the Code is amended to provide for a limitation different from that set forth in this Section, such different limitation shall be deemed incorporated herein effective as of the date and with respect to such Options as required or permitted by such amendment to the Code. If an Option is treated as an Incentive Stock Option in part and as a Nonstatutory Stock Option in part by reason of the limitation set forth in this Section, the Participant may designate which portion of such Option the Participant is exercising. In the absence of such designation, the Participant shall be deemed to have exercised the Incentive Stock Option portion of the Option first. Upon exercise, shares issued pursuant to each such portion shall be separately identified.

5.4 **Award Limits.**

(a) ***Maximum Number of Shares Issuable Pursuant to Incentive Stock Options.*** Subject to adjustment as provided in Section 4.2, the maximum aggregate number of shares of Stock that may be issued under the Plan pursuant to the exercise of Incentive Stock Options shall not exceed the number of shares set forth in the first sentence of Section 4.1 plus, to the extent allowable under Section 422 of the Code and the Treasury Regulations thereunder, any shares of Stock that again become available for issuance pursuant to the remaining provisions of Section 4.1.

(b) ***Section 162(m) Award Limits.*** Subject to adjustment as provided in Section 4.2, no Participant may be granted (i) Options or Stock Appreciation Rights during any calendar year with respect to more than 800,000 shares of Stock in the aggregate, and (ii) during any calendar year one or more Restricted Stock Awards, Restricted Stock Unit Awards or Performance Share Awards that are intended to comply with the performance-based exception under Code Section 162(m) for more than 1,600,000 shares of Stock in the aggregate; provided that, for this purpose, such limit shall be applied based on the maximum number of shares of Stock that may be earned under the applicable Award(s). During any calendar year no Participant may be granted Performance Units or other Awards that are intended to comply with the performance-based exception under Code Section 162(m) and are denominated in cash under which more than $20,000,000 may be earned in the aggregate. Each of the limitations in this section shall be multiplied by two with respect to Awards granted to a Participant during the first calendar year in which the Participant commences employment with the Company and its Subsidiaries. If an Award is cancelled, the cancelled Award shall continue to be counted toward the applicable limitation in this Section.

(c) ***Non-employee Director Award Limits.*** No Non-employee Director shall be granted Awards (including Non-employee Director Awards) in any calendar year having an aggregate Grant Date value in excess of $400,000. For this purpose, Restricted Stock Units, Restricted Stock Awards, Performance Awards, and other Awards shall be valued based on the Fair Market Value on the Grant Date of the maximum number of shares of Stock or dollars, as applicable, covered thereby and Options and SARs shall be valued using a Black-Scholes or other accepted valuation model, in each case, using reasonable assumptions.

5.5 **Dividends and Dividend Equivalents.** Notwithstanding anything herein to the contrary, cash dividends, stock and any other property (other than cash) distributed as a dividend, a Dividend Equivalent or otherwise with respect to any Award that vests based on achievement of Performance Goals (a) shall either (i) not be paid or credited or (ii) be accumulated, (b) shall be subject to restrictions and risk of forfeiture to the same extent as the underlying Award with respect to which such cash, stock or other property has been distributed and (c) shall be paid after such restrictions and risk of forfeiture lapse in accordance with the terms of the applicable Award Agreement.

6. **Terms and Conditions of Options .**

Options shall be evidenced by Award Agreements specifying the number of shares of Stock covered thereby, in such form as the Committee shall from time to time establish. No Option or purported Option shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Options may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

6.1 **Exercise Price .** The exercise price for each Option shall be established in the discretion of the Committee; provided, however, that (a) the exercise price per share shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the Option and (b) no Incentive Stock Option granted to a Ten Percent Owner shall have an exercise price per share less than one hundred ten percent (110%) of the Fair Market Value of a share of Stock on the effective date of grant of the Option. Notwithstanding the foregoing, an Option (whether an Incentive Stock Option or a Nonstatutory Stock Option) may be granted with an exercise price lower than the minimum exercise price set forth above if such Option is granted as a Substitute Award, except as would result in taxation under Section 409A or loss of ISO status.

6.2 **Exercisability and Term of Options .** Options shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such Option; provided, however, that (a) no Option shall be exercisable after the expiration of ten (10) years after the effective date of grant of such Option, (b) no Incentive Stock Option granted to a Ten Percent Owner shall be exercisable after the expiration of five (5) years after the effective date of grant of such Option, and (c) no Option granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service. Subject to the foregoing, unless otherwise specified by the Committee in the grant of an Option, any Option granted hereunder shall terminate ten (10) years after the effective date of grant of the Option, unless earlier terminated in accordance with its provisions.

6.3 **Payment of Exercise Price.**

(a) ***Forms of Consideration Authorized.*** Except as otherwise provided below, payment of the exercise price for the number of shares of Stock being purchased pursuant to any Option shall be made (i) in cash, by check or in cash equivalent, (ii) by tender to the Company, or attestation to the ownership, of shares of Stock owned by the Participant having a Fair Market Value not less than the exercise price, (iii) by delivery of a properly executed notice of exercise together with irrevocable instructions to a broker providing for the assignment to the Company of the proceeds of a sale or loan with respect to some or all of the shares being acquired upon the exercise of the Option (including, without limitation, through an exercise complying with the provisions of Regulation T as promulgated from time to time by the Board of Governors of the Federal Reserve System) (a ***" Cashless Exercise "***), (iv) by delivery of a properly executed notice of exercise electing a Net-Exercise, (v) by such other consideration as may be approved by the Committee from time to time to the extent permitted by applicable law, or (vi) by any combination thereof. The Committee may at any time or from time to time grant Options which do not permit all of the foregoing forms of consideration to be used in payment of the exercise price or which otherwise restrict one or more forms of consideration. Notwithstanding the foregoing, an Award Agreement may provide that if on the last day of the term of an Option the Fair Market Value of one share exceeds the option price per share, the Participant has not exercised the Option (or a tandem Stock Appreciation Right, if applicable) and the Option has not expired, the Option, to the extent vested, shall be deemed to have been exercised by the Participant on such day with payment made by withholding shares otherwise issuable in connection with the exercise of the Option. In such event, the Company shall deliver to the Participant the number of shares for which the Option was deemed exercised, less the number of shares required to be withheld for the payment of the total purchase price and required withholding taxes; provided, however, any fractional share shall be settled in cash.

(b) ***Limitations on Forms of Consideration.***

(i) **Tender of Stock.** Notwithstanding the foregoing, an Option may not be exercised by tender to the Company, or attestation to the ownership, of shares of Stock to the extent such tender or attestation would constitute a violation of the provisions of any law, regulation or agreement restricting the redemption of the Company's stock.

(ii) **Cashless Exercise.** The Company reserves, at any and all times, the right, in the Company's sole and absolute discretion, to establish, decline to approve or terminate any program or procedures for the exercise of Options by means of a Cashless Exercise, including with respect to one or more Participants specified by the Company notwithstanding that such program or procedures may be available to other Participants.

6.4 **Effect of Termination of Service.**

(a) ***Option Exercisability .*** Subject to earlier termination of the Option as otherwise provided herein and unless otherwise provided by the Committee, an Option shall be exercisable after a Participant's termination of Service only during the applicable time periods provided in the Award Agreement.

(b) ***Extension if Exercise Prevented by Law .*** Notwithstanding the foregoing, unless the Committee provides otherwise in the Award Agreement, if the exercise of an Option within the applicable time periods is prevented by the provisions of Section 15 below, the Option shall remain exercisable until three (3) months (or such longer period of time as determined by the Committee, in its discretion) after the date the Participant is notified by the Company that the Option is exercisable, but in any event no later than the earlier of the Option Expiration Date and the tenth anniversary of the date of grant of the Option.

(c) ***Extension if Exercise Prohibited by Law .*** Notwithstanding the foregoing, in the event that on the last business day of the term of an Option (other than an Incentive Stock Option) the exercise of the Option is prohibited by applicable law, the term of the Option shall be extended for a period of thirty (30) days following the end of the legal prohibition.

7. **<u>Terms and Conditions of Non-employee Director Awards</u> .**

Non-employee Director Awards granted under this Plan shall be automatic and non-discretionary and shall comply with and be subject to the terms and conditions set forth in this Section 7.

The grant date for all Non-employee Director awards to be made under this Section 7 shall be the later of (1) the date on which the independent inspector of election certifies the results of the annual election of directors by shareholders of PG&E Corporation or (2) the date that this Plan becomes effective and grants can be made consistent with legal requirements; provided, however, that in extraordinary circumstances, the grant shall be delayed until the first business day of the next open trading window period following certification of the director election results, as determined by the General Counsel of PG&E Corporation (the "Grant Date").

Grants made pursuant to this Section 7, but prior to January 1, 2015, shall be subject to the terms of Section 7 of the Prior Plan as in effect prior to the Effective Date, provided, however, that such grants shall be deemed made under this Plan.

7.1 **Grant of Restricted Stock Unit.**

(a) Timing and Amount of Grant. Each person who is a Non-employee Director on the Grant Date shall receive a grant of Restricted Stock Units with the number of Restricted Stock Units determined by dividing $140,000 by the Fair Market Value of the Stock on the Grant Date (rounded down to the nearest whole Restricted Stock Unit). The Restricted Stock Units awarded to a Non-employee Director shall be credited to the director's Restricted Stock Unit account. Each Restricted Stock Unit awarded to a Non-employee Director in accordance with this Section 7.1(a) shall be deemed to be equal to one (1) (or fraction thereof) share of Stock on the Grant Date, and the value of the Restricted Stock Unit shall thereafter fluctuate in value in accordance with the Fair Market Value of the Stock. No person shall receive more than one grant of Restricted Stock Units pursuant to this Section 7.1(a) during any calendar year.

(b) ***Dividend Rights*** . Each Non-employee Director's Restricted Stock Unit account shall be credited quarterly on each dividend payment date with additional shares of Restricted Stock Units (including fractions computed to three decimal places) determined by dividing (1) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the account by (2) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award.

(c) ***Vesting and Settlement of Restricted Stock Units*** . Restricted Stock Units shall vest on the earlier of (i) the first anniversary of the Grant Date or (ii) the last day of the director's elected term (the normal vesting date). Restricted Stock Units credited to a Non-employee Director's Restricted Stock Unit account shall, to the extent vested, be settled in a lump sum by the issuance of an equal number of shares of Stock, rounded down to the nearest whole share, upon the earliest of (i) the first anniversary of the Grant Date (normal settlement date), (ii) the Non-employee Director's death, (iii) the Non-employee Director's Disability (within the meaning of Section 409A of the Code), or (iv) the Non-employee Director's Separation from Service following a Change in Control. However, commencing with Restricted Stock Units having a Grant Date in 2015, a Non-employee Director may irrevocably elect, no later than December 31 of the calendar year prior to the Grant Date of the Restricted Stock Units (or such later time permitted by Section 409A) to have the Non-employee Director's Restricted Stock Unit account settled in (1) a series of 10 approximately equal annual installments (which shall be separate payments for purposes of Section 409A) commencing in January of any year following the normal settlement date, or (2) a lump sum in January of any future year following the normal settlement date. In the event that the Non-employee Director elects settlement of the Restricted Stock Units in accordance with the immediately preceding sentence, the Restricted Stock Units shall be earlier settled in a lump sum, to the extent vested, upon the occurrence of any of the events set forth in Section 7.1(c)(ii) through 7.1(c)(iv) prior to the elected settlement date (or commencement thereof in the case of settlement in 10 equal annual installments). In the event that a Non-employee Director elects to have the Non-employee Director's Restricted Stock Unit account settled in a series of 10 approximately equal annual installments commencing in January of any year following the normal settlement date and one of the events set forth in Section 7.1(c)(ii) through 7.1(c)(iv) occurs after commencement of such installments but prior to full settlement of the Non-employee Director's Restricted Stock Units, then any remaining unsettled Restricted Stock Units will be settled in a lump sum upon the occurrence of the applicable event but only to the extent that such acceleration would not result in the imposition of taxation under Section 409A. The Board may authorize other deferral alternatives with respect to Restricted Stock Units granted to Non-employee Directors, provided that such deferral alternatives comply with the deferral timing and other requirements of Section 409A. Such deferral alternatives may include, without limitation, deferral until the Non-employee Director's separation from service or until the January following such separation.

7.2 **Effect of Termination of Service as a Non-employee Director.**

(a) ***Forfeiture of Award .*** If the Non-employee Director has a Separation from Service prior to the normal vesting date, all Restricted Stock Units credited to the Participant's account that have not vested in accordance with Section 7.2(b) or 7.3 shall be forfeited to the Company and from and after the date of such Separation from Service, and the Participant shall cease to have any rights with respect thereto; provided, however, that if the Non-employee Director Separates from Service due to a pending Disability determination, such forfeiture shall not occur until a finding that such Disability has not occurred.

(b) ***Death or Disability*** . If the Non-employee Director becomes "disabled," within the meaning of Section 409A of the Code or in the event of the Non-employee Director's death, all Restricted Stock Units credited to the Non-employee Director's account shall immediately vest and become payable, in accordance with Section 7.1(c), to the Participant (or the Participant's legal representative or other person who acquired the rights to the Restricted Stock Units by reason of the Participant's death) in the form of a number of shares of Stock equal to the number of Restricted Stock Units credited to the Restricted Stock Unit account, rounded down to the nearest whole share.

(c) Notwithstanding the provisions of Section 7.1(c) above, the Board, in its sole discretion, may amend this Section 7 or establish different terms and conditions pertaining to Non-employee Director Awards.

7.3 **Effect of Change in Control on Non-employee Director Awards.** In the event a Non-employee Director ceases to be on the Board for any reason (other than resignation), following the occurrence of a Change in Control, all Restricted Stock Units shall immediately vest but shall not be settled until such time set forth in Section 7.1(c) occurs.

7.4 **Other Awards to Non-employee Directors** . Notwithstanding anything to the contrary set forth in this Plan, subject to Section 5.4(c) of the Plan, Non-employee Directors shall be eligible to receive all types of Awards under the Plan in addition to or instead of Non-employee Director Awards, as may be determined by the Board.

8. **Terms and Conditions of Stock Appreciation Rights .**

Stock Appreciation Rights shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No SAR or purported SAR shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing SARs may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

8.1 **Types of SARs Authorized.** SARs may be granted in tandem with all or any portion of a related Option (a *" **Tandem SAR** "* ) or may be granted independently of any Option (a *" **Freestanding SAR** "* ). A Tandem SAR may be granted either concurrently with the grant of the related Option or at any time thereafter prior to the complete exercise, termination, expiration or cancellation of such related Option.

8.2 **Exercise Price.** The exercise price for each SAR shall be established in the discretion of the Committee; provided, however, that (other than in connection with Substitute Awards granted in accordance with Code Section 424(a)): (a) the exercise price per share subject to a Tandem SAR shall be the exercise price per share under the related Option and (b) the exercise price per share subject to a Freestanding SAR shall be not less than the Fair Market Value of a share of Stock on the effective date of grant of the SAR.

8.3 **Exercisability and Term of SARs.**

(a) ***Tandem SARs.*** Tandem SARs shall be exercisable only at the time and to the extent, and only to the extent, that the related Option is exercisable, subject to such provisions as the Committee may specify where the Tandem SAR is granted with respect to less than the full number of shares of Stock subject to the related Option.

(b) ***Freestanding SARs.*** Freestanding SARs shall be exercisable at such time or times, or upon such event or events, and subject to such terms, conditions, performance criteria and restrictions as shall be determined by the Committee and set forth in the Award Agreement evidencing such SAR; provided, however, that no Freestanding SAR shall be exercisable after the expiration of ten (10) years after the effective date of grant of such SAR.

(c) ***Extension if Exercise Prevented by Law .*** Notwithstanding the foregoing, unless the Committee provides otherwise in the Award Agreement, if the exercise of an SAR within the applicable time periods is prevented by the provisions of Section 15 below, the SAR shall remain exercisable until three (3) months (or such longer period of time as determined by the Committee, in its discretion) after the date the Participant is notified by the Company that the SAR is exercisable, but in any event no later than the earlier of the date of expiration of the SAR's term (as set forth in the applicable Award Agreement) and the tenth anniversary of the date of grant of the SAR.

(d) ***Extension if Exercise Prohibited by Law .*** Notwithstanding the foregoing, in the event that on the last business day of the term of an SAR the exercise of the SAR is prohibited by applicable law, the term shall be extended for a period of thirty (30) days following the end of the legal prohibition.

8.4 **Deemed Exercise of SARs.** An Award Agreement may provide that if on the last day of the term of an SAR the Fair Market Value of one share exceeds the grant price per share of the Stock Appreciation Right, the Participant has not exercised the SAR or the tandem Option (if applicable), and the SAR has not otherwise expired, the SAR, to the extent then vested, shall be deemed to have been exercised by the Participant on such day. In such event, the Company shall make payment to the Participant in accordance with this Section, reduced by the number of shares (or cash) required for withholding taxes; any fractional share shall be settled in cash.

8.5 **Effect of Termination of Service.** Subject to earlier termination of the SAR as otherwise provided herein and unless otherwise provided by the Committee in the grant of an SAR and set forth in the Award Agreement, an SAR shall be exercisable after a Participant's termination of Service only as provided in the Award Agreement.

9. **Terms and Conditions of Restricted Stock Awards .**

Restricted Stock Awards shall be evidenced by Award Agreements specifying the number of shares of Stock subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Award or purported Restricted Stock Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

9.1 **Types of Restricted Stock Awards Authorized.** Restricted Stock Awards may or may not require the payment of cash compensation for the stock. Restricted Stock Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4 or other performance conditions established by the Committee. If either the grant of a Restricted Stock Award or the lapsing of the Restriction Period is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) for Awards intended to comply with the "qualified performance-based compensation" exception under Section 162(m) of the Code.

9.2 **Purchase Price.** The purchase price, if any, for shares of Stock issuable under each Restricted Stock Award and the means of payment shall be established by the Committee in its discretion.

9.3 **Purchase Period.** A Restricted Stock Award requiring the payment of cash consideration shall be exercisable within a period established by the Committee; provided, however, that no Restricted Stock Award granted to a prospective Employee, prospective Consultant or prospective Director may become exercisable prior to the date on which such person commences Service.

9.4 **Vesting and Restrictions on Transfer.** Shares issued pursuant to any Restricted Stock Award may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4, as shall be established by the Committee and set forth in the Award Agreement evidencing such Award. During any Restriction Period in which shares acquired pursuant to a Restricted Stock Award remain subject to Vesting Conditions, such shares may not be sold, exchanged, transferred, pledged, assigned or otherwise disposed of other than as provided in the Award Agreement or as provided in Section 18. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

9.5 **Voting Rights, Dividends and Distributions.** Except as provided in this Section, Section 9.4, Section 5.5, and any Award Agreement, during the Restriction Period applicable to shares subject to a Restricted Stock Award, the Participant shall have all of the rights of a shareholder of the Company holding shares of Stock, including the right to vote such shares and to receive all dividends and other distributions paid with respect to such shares. However, in the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2, any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant is entitled by reason of the Participant's Restricted Stock Award shall be immediately subject to the same Vesting Conditions as the shares subject to the Restricted Stock Award with respect to which such dividends or distributions were paid or adjustments were made.

9.6 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any shares acquired by the Participant pursuant to a Restricted Stock Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service in exchange for the payment of the purchase price, if any, paid by the Participant. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company.

10. **Terms and Conditions of Performance Awards**.

Performance Awards shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No Performance Award or purported Performance Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Performance Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions to the extent required under Section 162(m). Notwithstanding the foregoing, Awards that are not intended to comply with the "qualified performance-based compensation" exception under Section 162(m) may be subject to such other terms and conditions (which may be different from the terms and conditions set forth in this Section 10) as shall be determined by the Committee in its sole discretion.

10.1 **Types of Performance Awards Authorized.** Performance Awards may be in the form of either Performance Shares or Performance Units. Each Award Agreement evidencing a Performance Award shall specify the number of Performance Shares or Performance Units subject thereto, the Performance Award Formula, the Performance Goal(s) and Performance Period applicable to the Award, and the other terms, conditions and restrictions of the Award.

10.2 **Initial Value of Performance Shares and Performance Units.** Unless otherwise provided by the Committee in granting a Performance Award, each Performance Share shall have an initial value equal to the Fair Market Value of one (1) share of Stock, subject to adjustment as provided in Section 4.2, on the effective date of grant of the Performance Share. Each Performance Unit shall have an initial value determined by the Committee. The final value payable to the Participant in settlement of a Performance Award determined on the basis of the applicable Performance Award Formula will depend on the extent to which Performance Goals established by the Committee are attained within the applicable Performance Period established by the Committee.

10.3 **Establishment of Performance Period, Performance Goals and Performance Award Formula.** In granting each Performance Award, the Committee shall establish in writing the applicable Performance Period, Performance Award Formula and one or more Performance Goals which, when measured at the end of the Performance Period, shall determine on the basis of the Performance Award Formula the final value of the Performance Award to be paid to the Participant. To the extent compliance with the requirements under Section 162(m) with respect to "performance-based compensation" is desired, the Committee shall establish the Performance Goal(s) and Performance Award Formula applicable to each Performance Award no later than the earlier of (a) the date ninety (90) days after the commencement of the applicable Performance Period or (b) the date on which 25% of the Performance Period has elapsed, and, in any event, at a time when the outcome of the Performance Goals remains substantially uncertain. Once established, the Performance Goals and Performance Award

Formula for Awards intended to comply with the "qualified performance-based compensation" exception under Section 162(m) shall not be changed during the Performance Period, except as would result in the exercise of negative discretion by the Committee to reduce the amount of the Award otherwise payable as permitted under Section 162(m). The Company shall notify each Participant granted a Performance Award of the terms of such Award, including the Performance Period, Performance Goal(s) and Performance Award Formula.

10.4 **Measurement of Performance Goals.** Performance Goals shall be established by the Committee on the basis of targets to be attained ( " ***Performance Targets*** " ) with respect to one or more measures of business or financial performance (each, a " ***Performance Measure*** " ), subject to the following:

(a) ***Performance Measures.*** Performance Measures shall be calculated with respect to the Company and/or each Subsidiary Corporation and/or such division or other business unit as may be selected by the Committee, or may be based upon performance relative to performance of other companies or upon comparisons of any of the indicators of performance relative to performance of other companies. Performance Measures may be based upon one or more of the following objectively defined and non-discretionary business criteria and any other objectively verifiable and non-discretionary adjustments permitted and pre-established by the Committee in accordance with Section 162(m), as determined by the Committee: (i) sales revenue; (ii) gross margin; (iii) operating margin; (iv) operating income; (v) pre-tax profit; (vi) earnings before interest, taxes and depreciation and amortization (EBITDA)/adjusted EBITDA; (vii) net income; (viii) expenses; (ix) the market price of the Stock; (x) earnings per share; (xi) return on shareholder equity or assets; (xii) return on capital; (xiii) return on net assets; (xiv) economic profit or economic value added (EVA); (xv) market share; (xvi) customer satisfaction; (xvii) safety; (xviii) total shareholder return; (xix) earnings; (xx) cash flow; (xxi) revenue; (xxii) profits before interest and taxes; (xxiii) profit/loss; (xxiv) profit margin; (xxv) working capital; (xxvi) price/earnings ratio; (xxvii) debt or debt-to-equity; (xxviii) accounts receivable; (xxix) write-offs; (xxx) cash; (xxxi) assets; (xxxii) liquidity; (xxxiii) earnings from operations; (xxxiv) operational reliability; (xxxv) environmental performance; (xxxvi) funds from operations; (xxxvii) adjusted revenues; (xxxviii) free cash flow; (xxxix) core earnings; or (xxxx) operational performance.

(b) ***Performance Targets.*** Performance Targets may include a minimum, maximum, target level and intermediate levels of performance, with the final value of a Performance Award determined under the applicable Performance Award Formula by the level attained during the applicable Performance Period. A Performance Target may be stated as an absolute value or as a value determined relative to a standard selected by the Committee.

10.5 **Settlement of Performance Awards.**

(a) ***Determination of Final Value.*** As soon as practicable, but no later than the 15th day of the third month following the completion of the Performance Period applicable to a Performance Award (or such shorter period set forth in an Award Agreement), the Committee shall certify in writing the extent to which the applicable Performance Goals have been attained and the resulting final value of the Award earned by the Participant and to be paid upon its settlement in accordance with the applicable Performance Award Formula no later than the 15 th day of the third month following the completion of such Performance Period (or such shorter period set forth in an Award Agreement).

(b) ***Discretionary Adjustment of Award Formula.*** In its discretion, the Committee may, either at the time it grants a Performance Award or at any time thereafter, provide for the positive or negative adjustment of the Performance Award Formula applicable to a Performance Award that is not intended to constitute "qualified performance-based compensation" to a "covered employee" within the meaning of Section 162(m) (a " ***Covered Employee*** " ) to reflect such Participant's individual performance in his or her position with the Company or such other factors as the Committee may determine. With respect to a Performance Award intended to constitute qualified performance-based compensation to a Covered Employee, the Committee shall have the discretion to reduce (but not increase) some or all of the value of the Performance Award that would otherwise be paid to the Covered Employee upon its settlement notwithstanding the attainment of any Performance Goal and the resulting value of the Performance Award determined in accordance with the Performance Award Formula.

(c) ***Payment in Settlement of Performance Awards.*** As soon as practicable following the Committee's determination and certification in accordance with Sections 10.5(a) and (b) but, in any case, no later than the 15th day of the third month following completion of the Performance Period applicable to a Performance Award (or such shorter period set forth in an Award Agreement), payment shall be made to each eligible Participant (or such Participant's legal representative or other person who acquired the right to receive such payment by reason of the Participant's death) of the final value of the Participant's Performance Award. Payment of such amount shall be made in cash, shares of Stock, or a combination thereof as determined by the Committee.

10.6 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Performance Share Awards until the date of the issuance of such shares, if any (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Performance Share Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which the Performance Shares are settled or forfeited. Such Dividend Equivalents, if any, shall be credited to the Participant in the form of additional whole Performance Shares as of the date of payment of such cash dividends on Stock. The number of additional Performance Shares (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Performance Shares previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Dividend Equivalents credited in connection with Performance Shares shall be subject to Section 5.5 of the Plan. Settlement of Dividend Equivalents may be made in cash, shares of Stock, or a combination thereof as determined by the Committee, and may be paid on the same basis as settlement of the related Performance Share as provided in Section 10.5. Dividend Equivalents shall not be paid with respect to Performance Units. In the event of an adjustment described in Section 4.2, the adjusted Performance Share Award shall be immediately subject to the same Performance Goals as are applicable to the Award.

10.7 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Performance Award and set forth in the Award Agreement, the effect of a Participant's termination of Service on the Performance Award shall be as follows:

(a) ***Death or Disability.*** If the Participant's Service terminates because of the death or Disability of the Participant before the completion of the Performance Period applicable to the Performance Award, the final value of the Participant's Performance Award shall be determined by the extent to which the applicable Performance Goals have been attained with respect to the entire Performance Period and shall be prorated based on the number of months of the Participant's Service during the Performance Period. Payment shall be made following the end of the Performance Period in any manner permitted by Section 10.5.

(b) ***Other Termination of Service.*** If the Participant's Service terminates for any reason except death or Disability before the completion of the Performance Period applicable to the Performance Award, such Award shall be forfeited in its entirety; provided, however, that in the event of termination of the Participant's Service for other reasons, the Committee, in its sole discretion, may waive the automatic forfeiture of all or any portion of any such Award, to the extent consistent with the preservation of the tax deductibility of awards pursuant to Section 162(m) of the Code.

11. **Terms and Conditions of Restricted Stock Unit Awards** .

Restricted Stock Unit Awards shall be evidenced by Award Agreements specifying the number of Restricted Stock Units subject to the Award, in such form as the Committee shall from time to time establish. No Restricted Stock Unit Award or purported Restricted Stock Unit Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Restricted Stock Units may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

11.1 **Grant of Restricted Stock Unit Awards.** Restricted Stock Unit Awards may be granted upon such conditions as the Committee shall determine, including, without limitation, upon the attainment of one or more Performance Goals described in Section 10.4. If either the grant of a Restricted Stock Unit Award or the Vesting Conditions with respect to such Award is to be contingent upon the attainment of one or more Performance Goals, the Committee shall follow procedures substantially equivalent to those set forth in Sections 10.3 through 10.5(a) for Awards intended to comply with the "qualified performance-based compensation" exception under Section 162(m).

11.2 **Vesting.** Restricted Stock Units may or may not be made subject to Vesting Conditions based upon the satisfaction of such Service requirements, conditions, restrictions or performance criteria, including, without limitation, Performance Goals as described in Section 10.4, as shall be established by the Committee and set forth in the Award Agreement evidencing such Award.

11.3 **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Restricted Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the Award Agreement evidencing any Restricted Stock Unit Award that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Restricted Stock Units held by such Participant are settled. Such Dividend Equivalents, if any, shall be paid by crediting the Participant with additional whole Restricted Stock Units as of the date of payment of such cash dividends on Stock. The number of additional Restricted Stock Units (rounded to the nearest whole number) to be so credited shall be determined by dividing (a) the amount of cash dividends paid on such date with respect to the number of shares of Stock represented by the Restricted Stock Units previously credited to the Participant by (b) the Fair Market Value per share of Stock on such date. Such additional Restricted Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Restricted Stock Units originally subject to the Restricted Stock Unit Award, provided that Dividend Equivalents may be settled in cash, shares of Stock, or a combination thereof as determined by the Committee and set forth in the Award Agreement. In the event of an adjustment as described in Section 4.2, the Participant's adjusted Restricted Stock Unit Award shall be immediately subject to the same Vesting Conditions as are applicable to the Award.

11.4 **Effect of Termination of Service.** Unless otherwise provided by the Committee in the grant of a Restricted Stock Unit Award and set forth in the Award Agreement, if a Participant's Service terminates for any reason, whether voluntary or involuntary (including the Participant's death or disability), then the Participant shall forfeit to the Company any Restricted Stock Units pursuant to the Award which remain subject to Vesting Conditions as of the date of the Participant's termination of Service.

11.5 **Settlement of Restricted Stock Unit Awards .** The Company shall issue to a Participant on the date on which Restricted Stock Units subject to the Participant's Restricted Stock Unit Award vest or on such other date determined by the Committee, in its discretion, and set forth in the Award Agreement one (1) share of Stock (and/or any other new, substituted or additional securities or other property pursuant to an adjustment described in Section 11.3) for each Restricted Stock Unit then becoming vested or otherwise to be settled on such date, subject to the withholding of applicable taxes, provided that Restricted Stock Units may be settled in cash, shares of Stock, or a combination thereof as determined by the Committee and set forth in the Award Agreement. Notwithstanding the foregoing, if permitted by the Committee and set forth in the Award Agreement and subject to the restrictions of Section 409A of the Code, the Participant may elect in accordance with terms specified in the Award Agreement to defer receipt of all or any portion of the shares of Stock or other property otherwise issuable to the Participant pursuant to this Section.

12. **Deferred Compensation Awards** .

12.1 **Establishment of Deferred Compensation Award Programs.** This Section 12 shall not be effective unless and until the Committee determines to establish a program pursuant to this Section. The Committee, in its discretion and upon such terms and conditions as it may determine, may establish one or more programs pursuant to the Plan under which:

(a) Subject to the restrictions of Section 409A of the Code, Participants designated by the Committee who are Insiders or otherwise among a select group of management or highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to reduce such Participant's compensation otherwise payable in cash (subject to any minimum or maximum reductions imposed by the Committee) and to be granted automatically at such time or times as specified by the Committee one or more Awards of Stock Units with respect to such numbers of shares of Stock as determined in accordance with the rules of the program established by the Committee and having such other terms and conditions as established by the Committee.

(b) Subject to the restrictions of Section 409A of the Code, Participants designated by the Committee who are Insiders or otherwise among a select group of management or highly compensated Employees may irrevocably elect, prior to a date specified by the Committee, to be granted automatically an Award of Stock Units with respect to such number of shares of Stock and upon such other terms and conditions as established by the Committee in lieu of cash or shares of Stock otherwise issuable to such Participant upon the settlement of a Performance Award or Performance Unit.

12.2 **Terms and Conditions of Deferred Compensation Awards.** Deferred Compensation Awards granted pursuant to this Section 12 shall be evidenced by Award Agreements in such form as the Committee shall from time to time establish. No such Deferred Compensation Award or purported Deferred Compensation Award shall be a valid and binding obligation of the Company unless evidenced by a fully executed Award Agreement. Award Agreements evidencing Deferred Compensation Awards may incorporate all or any of the terms of the Plan by reference and shall comply with and be subject to the following terms and conditions:

(a) *Vesting Conditions* . Deferred Compensation Awards shall or shall not be subject to vesting conditions, as determined by the Committee.

(b) ***Terms and Conditions of Stock Units*** .

(i) **Voting Rights, Dividend Equivalent Rights and Distributions.** Participants shall have no voting rights with respect to shares of Stock represented by Stock Units until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). However, the Committee, in its discretion, may provide in the applicable Award Agreement that the Participant shall be entitled to receive Dividend Equivalents with respect to the payment of cash dividends on Stock having a record date prior to the date on which Stock Units held by such Participant are settled. Such Dividend Equivalents shall be paid by crediting the Participant with additional whole and/or fractional Stock Units as of the date of payment of such cash dividends on Stock. The method of determining the number of additional Stock Units to be so credited shall be specified by the Committee and set forth in the Award Agreement. Such additional Stock Units shall be subject to the same terms and conditions and shall be settled in the same manner and at the same time as the Stock Units originally subject to the Stock Unit Award. In the event of a dividend or distribution paid in shares of Stock or any other adjustment made upon a change in the capital structure of the Company as described in Section 4.2, appropriate adjustments shall be made in the Participant's Stock Unit Award so that it represents the right to receive upon settlement any and all new, substituted or additional securities or other property (other than normal cash dividends) to which the Participant would be entitled by reason of the shares of Stock issuable upon settlement of the Award.

(ii) **Settlement of Stock Unit Awards.** A Participant electing to receive an Award of Stock Units pursuant to this Section 12, shall specify at the time of such election a settlement date with respect to such Award in accordance with rules established by the Committee. Except as otherwise set forth in the applicable Award Agreement, the Company shall issue to the Participant upon the earlier of the settlement date elected by the Participant or the date of the Participant's Separation from Service, a number of whole shares of Stock equal to the number of whole Stock Units subject to the Stock Unit Award. The Participant shall not be required to pay any additional consideration (other than applicable tax withholding) to acquire such shares. Any fractional Stock Unit subject to the Stock Unit Award shall be settled by the Company by payment in cash of an amount equal to the Fair Market Value as of the payment date of such fractional share.

13. **Other Stock-Based Awards** .

In addition to the Awards set forth in Sections 6 through 12 above, the Committee, in its sole discretion, may carry out the purpose of this Plan by awarding Stock-Based Awards as it determines to be in the best interests of the Company and subject to such other terms and conditions as it deems necessary and appropriate. Such awards may be evidenced by Award Agreements in such form as the Committee shall from time to time establish.

14. **Change in Control .**

14.1 **Effect of Change in Control .** Except as set forth in an applicable Award Agreement, in the event of a Change in Control, the surviving, continuing, successor, or purchasing corporation or other business entity or parent thereof, as the case may be (the "Acquiror "), may, without the consent of any Participant, either assume or continue the Company's rights and obligations under outstanding Awards or substitute for such Awards substantially equivalent Awards covering the Acquiror's stock. Except as set forth in an applicable Award Agreement, any such Awards which are neither assumed, continued, or substituted by the Acquiror in connection with the Change in Control nor exercised (if applicable) as of the Change in Control shall, contingent on the Change in Control, become fully vested, and Options and SARs become exercisable immediately prior to the Change in Control. Except as set forth in an applicable Award Agreement, Awards which are assumed or continued in connection with a Change in Control shall be subject to such additional accelerated vesting and/or exercisability, or lapse of restrictions in connection with the Participant's termination of Service in connection with the Change in Control as the Committee or Board may determine, if any.

14.2 **Non-employee Director Awards** . Notwithstanding the foregoing, Non-employee Director Awards shall be subject to the terms of Section 7, and not this Section 14.

15. **Compliance with Securities Law .**

The grant of Awards and the issuance of shares of Stock pursuant to any Award shall be subject to compliance with all applicable requirements of federal, state and foreign law with respect to such securities and the requirements of any stock exchange or market system upon which the Stock may then be listed. In addition, no Award may be exercised or shares issued pursuant to an Award unless (a) a registration statement under the Securities Act shall at the time of such exercise or issuance be in effect with respect to the shares issuable pursuant to the Award or (b) in the opinion of legal counsel to the Company, the shares issuable pursuant to the Award may be issued in accordance with the terms of an applicable exemption from the registration requirements of the Securities Act. The inability of the Company to obtain from any regulatory body having jurisdiction the authority, if any, deemed by the Company's legal counsel to be necessary to the lawful issuance and sale of any shares hereunder shall relieve the Company of any liability in respect of the failure to issue or sell such shares as to which such requisite authority shall not have been obtained. As a condition to issuance of any Stock, the Company may require the Participant to satisfy any qualifications that may be necessary or appropriate, to evidence compliance with any applicable law or regulation and to make any representation or warranty with respect thereto as may be requested by the Company.

16. **Tax Withholding .**

16.1 **Tax Withholding in General.** The Company shall have the right to deduct from any and all payments made under the Plan, or to require the Participant, through payroll withholding, cash payment or otherwise, including by means of a Cashless Exercise or Net Exercise of an Option, to make adequate provision for, the federal, state, local and foreign taxes, if any, required by law to be withheld by the Participating Company Group with respect to an Award or the shares acquired pursuant thereto. The Company shall have no obligation to deliver shares of Stock, to release shares of Stock from an escrow established pursuant to an Award Agreement, or to make any payment in cash under the Plan unless the Participating Company Group's tax withholding obligations have been satisfied by the Participant.

16.2 **Withholding in Shares.** The Company shall have the right, but not the obligation, to deduct from the shares of Stock issuable to a

Participant upon the exercise or settlement of an Award, or to accept from the Participant the tender of, a number of whole shares of Stock having a Fair Market Value, as determined by the Company, equal to all or any part of the tax withholding obligations of the Participating Company Group. Notwithstanding the foregoing, the Fair Market Value of any shares of Stock withheld or tendered to satisfy any such tax withholding obligations shall not exceed the amount determined by the applicable minimum statutory withholding rates to the extent required to avoid adverse accounting or other consequences to the Company or Participant.

17. **Amendment or Termination of Plan .**

The Board or the Committee may amend, suspend or terminate the Plan at any time. However, without the approval of the Company's shareholders, there shall be (a) no increase in the maximum aggregate number of shares of Stock that may be issued under the Plan (except by operation of the provisions of Section 4.2), (b) no change in the class of persons eligible to receive Incentive Stock Options, (c) no amendment to Section 5.4(b) or 5.4(c), and (d) no other amendment of the Plan that would require approval of the Company's shareholders under any applicable law, regulation or rule. Notwithstanding the foregoing, only the Board may amend Section 7 and may do so without the approval of the Company's shareholders. No amendment, suspension or termination of the Plan shall affect any then outstanding Award unless expressly provided by the Board or the Committee. In any event, no amendment, suspension or termination of the Plan may adversely affect any then outstanding Award without the consent of the Participant unless necessary to comply with any applicable law, regulation or rule.

18. **Miscellaneous Provisions .**

18.1 **Repurchase Rights .** Shares issued under the Plan may be subject to one or more repurchase options, or other conditions and restrictions as determined by the Committee in its discretion at the time the Award is granted. The Company shall have the right to assign at any time any repurchase right it may have, whether or not such right is then exercisable, to one or more persons as may be selected by the Company. Upon request by the Company, each Participant shall execute any agreement evidencing such transfer restrictions prior to the receipt of shares of Stock hereunder and shall promptly present to the Company any and all certificates representing shares of Stock acquired hereunder for the placement on such certificates of appropriate legends evidencing any such transfer restrictions.

18.2 **Provision of Information.** Each Participant shall be given access to information concerning the Company equivalent to that information generally made available to the Company's common shareholders.

18.3 **Rights as Employee, Consultant or Director.** No person, even though eligible pursuant to Section 5, shall have a right to be selected as a Participant, or, having been so selected, to be selected again as a Participant. Nothing in the Plan or any Award granted under the Plan shall confer on any Participant a right to remain an Employee, Consultant or Director or interfere with or limit in any way any right of a Participating Company to terminate the Participant's Service at any time. To the extent that an Employee of a Participating Company other than the Company receives an Award under the Plan, that Award shall in no event be understood or interpreted to mean that the Company is the Employee's employer or that the Employee has an employment relationship with the Company. A Participant's rights, if any, in respect of or in connection with any Award is derived solely from the discretionary decision of the Company to permit the individual to participate in the Plan and to benefit from a discretionary Award. By accepting an Award under the Plan, a Participant expressly acknowledges that there is no obligation on the part of the Company to continue the Plan and/or grant any additional Awards. Any Award granted hereunder is not intended to be compensation of a continuing or recurring nature, or part of a Participant's normal or expected compensation, and in no way represents any portion of a Participant's salary, compensation, or other remuneration for purposes of pension benefits, severance, redundancy, resignation or any other purpose. The Company and its Parent Corporations and Subsidiary Corporations and Affiliates reserve the right to terminate the Service of any person at any time, and for any reason, subject to applicable laws and such person's written employee agreement (if any), and such terminated person shall be deemed irrevocably to have waived any claim to damages or specific performance for breach of contract or dismissal, compensation for loss of office, tort or otherwise with respect to the Plan or any outstanding Award that is forfeited and/or is terminated by its terms or to any future Award.

18.4 **Rights as a Shareholder.** A Participant shall have no rights as a shareholder with respect to any shares covered by an Award until the date of the issuance of such shares (as evidenced by the appropriate entry on the books of the Company or of a duly authorized transfer agent of the Company). No adjustment shall be made for dividends, distributions or other rights for which the record date is prior to the date such shares are issued, except as provided in another provision of the Plan.

18.5 **Fractional Shares.** The Company shall not be required to issue fractional shares upon the exercise or settlement of any Award.

18.6 **Severability .** If any one or more of the provisions (or any part thereof) of this Plan shall be held invalid, illegal or unenforceable in any respect, such provision shall be modified so as to make it valid, legal and enforceable, and the validity, legality and enforceability of the remaining provisions (or any part thereof) of the Plan shall not in any way be affected or impaired thereby.

18.7 **Beneficiary Designation.** Subject to local laws and procedures, each Participant may file with the Company a written designation of a beneficiary who is to receive any benefit under the Plan to which the Participant is entitled in the event of such Participant's death before he or she receives any or all of such benefit. Each designation will revoke all prior designations by the same Participant, shall be in a form prescribed by the Company, and will be effective only when filed by the Participant in writing with the Company during the Participant's lifetime. If a married Participant designates a beneficiary other than the Participant's spouse, the effectiveness of such designation may be subject to the consent of the Participant's spouse. If a Participant dies without an effective designation of a beneficiary who is living at the time of the Participant's death, the Company will pay any remaining unpaid benefits to the Participant's legal representative.

18.8 **Unfunded Obligation.** Participants shall have the status of general unsecured creditors of the Company. Any amounts payable to Participants pursuant to the Plan shall be unfunded and unsecured obligations for all purposes, including, without limitation, Title I of the Employee Retirement Income Security Act of 1974. No Participating Company shall be required to segregate any monies from its general funds, or to create any trusts, or establish any special accounts with respect to such obligations. The Company shall retain at all times beneficial ownership of any investments, including trust investments, which the Company may make to fulfill its payment obligations hereunder. Any investments or the creation or maintenance of any trust or any Participant account shall not create or constitute a trust or fiduciary relationship between the Committee or any Participating Company and a Participant, or otherwise create any vested or beneficial interest in any Participant or the Participant's creditors in any assets of any Participating Company. The Participants shall have no claim against any

Participating Company for any changes in the value of any assets which may be invested or reinvested by the Company with respect to the Plan. Each Participating Company shall be responsible for making benefit payments pursuant to the Plan on behalf of its Participants or for reimbursing the Company for the cost of such payments, as determined by the Company in its sole discretion. In the event the respective Participating Company fails to make such payment or reimbursement, a Participant's (or other individual's) sole recourse shall be against the respective Participating Company, and not against the Company. A Participant's acceptance of an Award pursuant to the Plan shall constitute agreement with this provision.

18.9 **Choice of Law.** Except to the extent governed by applicable federal law, the validity, interpretation, construction and performance of the Plan and each Award Agreement shall be governed by the laws of the State of California, without regard to its conflict of law rules.

18.10 **Section 409A of the Code.** Notwithstanding anything to the contrary in the Plan, to the extent (i) any Award payable in connection with a Participant's Separation from Service constitutes deferred compensation subject to (and not exempt from) Section 409A of the Code and (ii) the Participant is deemed at the time of such separation to be a "specified employee" under Section 409A of the Code and the Treasury regulations thereunder, then payment shall not be made or commence until the earlier of (i) six (6)-months after such Separation from Service or (ii) the date of the Participant's death following such Separation from Service; provided, however, that such delay shall only be effected to the extent required to avoid adverse tax treatment to the Participant, including (without limitation) the additional twenty percent (20%) tax for which the Participant would otherwise be liable under Section 409A(a)(1)(B) of the Code in the absence of such delay. Upon the expiration of the applicable delay period, any payment which would have otherwise been paid during that period (whether in a single sum or in installments) in the absence of this paragraph shall be paid to the Participant or the Participant's beneficiary in one lump sum on the first business day immediately following such delay and any undelayed payments will be paid in accordance with their normal terms.

18.11 **Restrictions on Transfer** . No Award and no shares of Stock that have not been issued or as to which any applicable restriction, performance or deferral period has not lapsed, may be sold, assigned, transferred, pledged or otherwise encumbered, other than by will or the laws of decent and distribution, and such Award may be exercised during the life of the Participant only by the Participant or the Participant's guardian or legal representative. Notwithstanding the foregoing, to the extent permitted by the Committee, in its discretion, and set forth in the applicable Award Agreement, an Award shall be assignable or transferrable to a "family member" or other permitted transferee to the extent covered under Form S-8 Registration Statement under the Securities Act.

PLAN HISTORY AND NOTES TO COMPANY

| | |
|---|---|
| February 19, 2014 | Board adopts Plan with a reserve of 17 million shares, less one share for every one share of Stock covered by an award granted under the Prior Plan after December 31, 2013 and prior to the Effective Date. |
| May 12, 2014 | Shareholders approve Plan. Plan Effective Date |
| January 1, 2015 | Non-employee director awards amended to:<br>Increase the value of annual awards to $120,000 from $105,000.<br><br>Change the vesting date to the earlier of the anniversary of the grant date or the last day of the director's elected term. |
| January 1, 2016 | The value of annual LTIP awards to non-employee directors increased to $140,000 from $120,000. |
| February 15, 2017 | CEO no longer required to be PG&E Corporation director in order to make certain types of LTIP awards.<br>Expand deferral options for non-employee director awards. |

**EXHIBIT 12.1**
**PACIFIC GAS AND ELECTRIC COMPANY**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| **(in millions)** | **2017** | **2016** | **2015** | **2014** | **2013** |
| **Earnings:** | | | | | |
| Net income | $ 1,691 | $ 1,402 | $ 862 | $ 1,433 | $ 866 |
| Income tax provision (benefit) | 427 | 70 | (19) | 384 | 326 |
| Fixed charges | 1,572 | 1,417 | 1,260 | 1,176 | 971 |
| **Total earnings** | **$ 3,690** | **$ 2,889** | **$ 2,103** | **$ 2,993** | **$ 2,163** |
| **Fixed charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 1,532 | $ 1,363 | $ 1,208 | $ 1,125 | $ 917 |
| Interest on capital leases | 2 | 3 | 4 | 6 | 7 |
| AFUDC debt | 38 | 51 | 48 | 45 | 47 |
| **Total fixed charges** | **$ 1,572** | **$ 1,417** | **$ 1,260** | **$ 1,176** | **$ 971** |
| **Ratios of earnings to fixed charges** | **2.35** | **2.04** | **1.67** | **2.55** | **2.23** |

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to fixed charges, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. Fixed charges exclude interest on tax liabilities.

**EXHIBIT 12.2**
**PACIFIC GAS AND ELECTRIC COMPANY**
**COMPUTATION OF RATIOS OF EARNINGS TO COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| **(in millions)** | **2017** | **2016** | **2015** | **2014** | **2013** |
| **Earnings:** | | | | | |
| Net income | $ 1,691 | $ 1,402 | $ 862 | $ 1,433 | $ 866 |
| Income tax provision (benefit) | 427 | 70 | (19) | 384 | 326 |
| Fixed charges | 1,572 | 1,417 | 1,260 | 1,176 | 971 |
| **Total earnings** | **$ 3,690** | **$ 2,889** | **$ 2,103** | **$ 2,993** | **$ 2,163** |
| **Fixed charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 1,532 | $ 1,363 | $ 1,208 | $ 1,125 | $ 917 |
| Interest on capital leases | 2 | 3 | 4 | 6 | 7 |
| AFUDC debt | 38 | 51 | 48 | 45 | 47 |
| **Total fixed charges** | **$ 1,572** | **$ 1,417** | **$ 1,260** | **$ 1,176** | **$ 971** |
| **Preferred stock dividends:** | | | | | |
| Tax deductible dividends | $ 9 | $ 9 | $ 9 | $ 9 | $ 9 |
| Pre-tax earnings required to cover non-tax deductible preferred stock dividend requirements | 7 | 5 | 5 | 6 | 7 |
| **Total preferred stock dividends** | **16** | **14** | **14** | **15** | **16** |
| **Total combined fixed charges and preferred stock dividends** | **$ 1,588** | **$ 1,431** | **$ 1,274** | **$ 1,191** | **$ 987** |
| **Ratios of earnings to combined fixed charges and preferred stock dividends** | **2.32** | **2.02** | **1.65** | **2.51** | **2.19** |

Note:
For the purpose of computing Pacific Gas and Electric Company's ratios of earnings to combined fixed charges and preferred stock dividends, "earnings" represent net income adjusted for the income or loss from equity investees of less than 100% owned affiliates, equity in undistributed income or losses of less than 50% owned affiliates, income taxes and fixed charges (excluding capitalized interest). "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover the preferred stock dividend requirements. "Preferred stock dividends" represent tax deductible dividends and pre-tax earnings that are required to pay the dividends on outstanding preferred securities. Fixed charges exclude interest on tax liabilities.

**EXHIBIT 12.3**
**PG&E CORPORATION**
**COMPUTATION OF RATIOS OF EARNINGS TO FIXED CHARGES**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| **(in millions)** | **2017** | **2016** | **2015** | **2014** | **2013** |
| **Earnings:** | | | | | |
| Net income | $ 1,660 | $ 1,407 | $ 888 | $ 1,450 | $ 828 |
| Income tax provision (benefit) | 511 | 55 | (27) | 345 | 268 |
| Fixed charges | 1,598 | 1,440 | 1,284 | 1,206 | 1,012 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries | (15) | (14) | (14) | (15) | (16) |
| **Total earnings** | **$ 3,754** | **$ 2,888** | **$ 2,131** | **$ 2,986** | **$ 2,092** |
| **Fixed charges:** | | | | | |
| Interest on short-term borrowings and long-term debt, net | $ 1,543 | $ 1,372 | $ 1,218 | $ 1,140 | $ 942 |
| Interest on capital leases | 2 | 3 | 4 | 6 | 7 |
| AFUDC debt | 38 | 51 | 48 | 45 | 47 |
| Pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries | 15 | 14 | 14 | 15 | 16 |
| **Total fixed charges** | **$ 1,598** | **$ 1,440** | **$ 1,284** | **$ 1,206** | **$ 1,012** |
| **Ratios of earnings to fixed charges** | **2.35** | **2.01** | **1.66** | **2.48** | **2.07** |

Note:
For the purpose of computing PG&E Corporation's ratios of earnings to fixed charges, "earnings" represent income from continuing operations adjusted for income taxes, fixed charges (excluding capitalized interest), and pre-tax earnings required to cover the preferred stock dividend of consolidated subsidiaries. "Fixed charges" include interest on long-term debt and short-term borrowings (including a representative portion of rental expense), amortization of bond premium, discount and expense, interest on capital leases, AFUDC debt, and earnings required to cover preferred stock dividends of consolidated subsidiaries. Fixed charges exclude interest on tax liabilities.

**EXHIBIT 21**

**Significant Subsidiaries**

| Parent of Significant Subsidiary | Name of Significant Subsidiary | Jurisdiction of Formation of Subsidiary | Names under which Significant Subsidiary does business |
|---|---|---|---|
| PG&E Corporation | Pacific Gas and Electric Company | CA | Pacific Gas and Electric Company<br>PG&E |
| Pacific Gas and Electric Company | None | | |

**EXHIBIT 23.01**

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-215425 and 333-209586 on Form S-3, 333-129422, 333-176090, 333-195902 and 333-206457 on Form S-8 of our reports dated February 9, 2018, relating to the consolidated financial statements and financial statement schedules of PG&E Corporation and subsidiaries (the "Company") (which report on the consolidated financial statements expresses an unqualified opinion and includes an emphasis-of-matter paragraph regarding the uncertainty related to possible material losses or penalties to the Company as a result of the Northern California wildfires that occurred in October 2017), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 9, 2018

**EXHIBIT 23.02**

**CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM**

We consent to the incorporation by reference in Registration Statement No. 333-215427 on Form S-3 of our reports dated February 9, 2018, relating to the consolidated financial statements and financial statement schedule of Pacific Gas and Electric Company and subsidiaries (the "Utility") (which report on the consolidated financial statements expresses an unqualified opinion and includes an emphasis-of-matter paragraph regarding the uncertainty related to possible material losses or penalties to the Utility as a result of the Northern California wildfires that occurred in October 2017), and the effectiveness of the Utility's internal control over financial reporting, appearing in this Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2017.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California
February 9, 2018

# POWER OF ATTORNEY

Each of the undersigned Directors of PG&E Corporation hereby constitutes and appoints JOHN R. SIMON, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, and ERIC A. MONTIZAMBERT, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2017 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 7th day of February 2018.

| | |
|---|---|
| /s/ Lewis Chew<br>Lewis Chew | /s/ Forrest E. Miller<br>Forrest E. Miller |
| /s/ Fred J. Fowler<br>Fred J. Fowler | /s/ Eric D. Mullins<br>Eric D. Mullins |
| /s/ Jeh C. Johnson<br>Jeh C. Johnson | /s/ Rosendo G. Parra<br>Rosendo G. Parra |
| /s/ Richard C. Kelly<br>Richard C. Kelly | /s/ Barbara L. Rambo<br>Barbara L. Rambo |
| /s/ Roger H. Kimmel<br>Roger H. Kimmel | /s/ Anne Shen Smith<br>Anne Shen Smith |
| /s/ Richard A. Meserve<br>Richard A. Meserve | /s/ Geisha J. Williams<br>Geisha J. Williams |

**POWER OF ATTORNEY**

Each of the undersigned Directors of Pacific Gas and Electric Company hereby constitutes and appoints JOHN R. SIMON, LINDA Y.H. CHENG, EILEEN O. CHAN, WONDY S. LEE, and ERIC A. MONTIZAMBERT, and each of them, as his or her attorneys in fact with full power of substitution to sign and file with the Securities and Exchange Commission in his or her capacity as such Director of said corporation the Annual Report on Form 10-K for the year ended December 31, 2017 required by Section 13 or 15(d) of the Securities Exchange Act of 1934 and any and all amendments and other filings or documents related thereto, and hereby ratifies all that said attorneys in fact or any of them may do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, we have signed these presents this 7th day of February 2018.

/s/ Lewis Chew
Lewis Chew

/s/ Fred J. Fowler
Fred J. Fowler

/s/ Richard C. Kelly
Richard C. Kelly

/s/ Roger H. Kimmel
Roger H. Kimmel

/s/ Richard A. Meserve
Richard A. Meserve

/s/ Forrest E. Miller
Forrest E. Miller

/s/ Eric D. Mullins
Eric D. Mullins

/s/ Rosendo G. Parra
Rosendo G. Parra

/s/ Barbara L. Rambo
Barbara L. Rambo

/s/ Anne Shen Smith
Anne Shen Smith

/s/ Nickolas Stavropoulos
Nickolas Stavropoulos

/s/ Geisha J. Williams
Geisha J. Williams

**EXHIBIT 31.1**

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Geisha J. Williams , certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2017 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) ) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2018

GEISHA J. WILLIAMS

Geisha J. Williams
Chief Executive Officer and President

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Jason P. Wells, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2017 of PG&E Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2018

JASON P. WELLS

Jason P. Wells
Senior Vice President and Chief Financial Officer

**EXHIBIT 31.2**

CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, Nickolas Stavropoulos, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2017 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f) ) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2018

NICKOLAS STAVROPOULOS
Nickolas Stavropoulos
President and Chief Operating Officer

CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
PURSUANT TO SECURITIES AND EXCHANGE COMMISSION RULE 13a-14(a)

I, David S. Thomason, certify that:

1. I have reviewed this Annual Report on Form 10-K for the year ended December 31, 2017 of Pacific Gas and Electric Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 9, 2018

DAVID S. THOMASON

David S. Thomason
Vice President, Chief Financial Officer and Controller

**EXHIBIT 32.1**

# CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2017 ("Form 10-K"), I, Geisha J. Williams, Chief Executive Officer and President of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

GEISHA J. WILLIAMS

GEISHA J. WILLIAMS
Chief Executive Officer and President

February 9, 2018

# CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
# PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Annual Report on Form 10-K of PG&E Corporation for the year ended December 31, 2017 ("Form 10-K"), I, Jason P. Wells, Senior Vice President and Chief Financial Officer of PG&E Corporation, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of PG&E Corporation.

JASON P. WELLS

JASON P. WELLS
Senior Vice President and
Chief Financial Officer

February 9, 2018

**EXHIBIT 32.2**

# CERTIFICATION OF PRINCIPAL EXECUTIVE OFFICER PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2017 ("Form 10-K"), I, Nickolas Stavropoulos, President and Chief Operating Office of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

NICKOLAS STAVROPOULOS

NICKOLAS STAVROPOULOS
President and Chief Operating Officer

February 9, 2018

# CERTIFICATION OF PRINCIPAL FINANCIAL OFFICER
# PURSUANT TO 18 U.S.C. SECTION 1350

In connection with the accompanying Annual Report on Form 10-K of Pacific Gas and Electric Company for the year ended December 31, 2017 ("Form 10-K"), I, David S. Thomason, Vice President, Chief Financial Officer and Controller of Pacific Gas and Electric Company, hereby certify pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, to the best of my knowledge and belief, that:

(1) the Form 10-K fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) the information contained in the Form 10-K fairly presents, in all material respects, the financial condition and results of operations of Pacific Gas and Electric Company.

DAVID S. THOMASON

DAVID S. THOMASON
Vice President, Chief Financial Officer and Controller

February 9, 2018