PG&E Corp
Form 10-K
February 09, 2018

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 Fiscal 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 Specified In Its Charter	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	77 Beale Street, P.O. Box 770000
San Francisco, California 94177	San Francisco, California 94177
(Address of principal executive offices) (Zip Code)	(Address of principal executive offices) (Zip Code)
(415) 973-1000	(415) 973-7000
(Registrant's telephone number, including area code)	(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
PG&E Corporation: Common Stock, no par value	New York Stock Exchange
Pacific Gas and Electric Company: First Preferred Stock,	NYSE MKT LLC

cumulative, par value $25 per share:
Redeemable: 5% Series A, 5%, 4.80%, 4.50%, 4.36%
Nonredeemable: 6%, 5.50%, 5%

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 Corporation	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)

2

Contents

3

4

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
CO2	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

6

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 Utility 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 Corporation'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 Francisco, 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, 2017, PG&E Corporation and the Utility had approximately 23,000 regular employees, approximately 20 of which 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 Engineers 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 Utility. PG&E Corporation's and the Utility's Annual Reports on Form 10-K, Quarterly Reports on Form 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 material information. The information contained on this website is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC. PG&E Corporation and the Utility are providing the address to this website solely for the information of investors and do not intend the address to be an active link. PG&E Corporation and the Utility also routinely post or provide direct links to presentations, documents, and other information that may be of interest to investors at http://investor.pgecorp.com, under the "News & Events: Events & Presentations" tab, in order to publicly disseminate such information.

This 2017 Form 10-K contains forward-looking statements that are necessarily subject to various risks and uncertainties. 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 operations, see Item 1A. Risk Factors and the section entitled "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 regulated 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 proceedings affecting the Utility.

PG&E Corporation is a "public utility holding company" as 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 obligation 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 service for the Utility's electric and natural gas distribution 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 good 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 authority to the SED to issue citations and impose penalties for violations identified through audits, investigations, or self-reports. Under the current gas and electric 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 penalties on a daily basis, or on less than a daily 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 regardless 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 recovered in rates or otherwise directly or indirectly 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 and 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. The CPUC 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 with regulatory guidelines.

The 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 Resources" in Item 7. MD&A and Item 1A. Risk Factors.)

The Federal Energy Regulatory Commission and the California Independent System Operator

The FERC has jurisdiction 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 transmission 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 reliability 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 impose fines of up to $1 million per day for violations 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 transmission 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 ensuring 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 "Electricity Resources" below.) NRC regulations require extensive monitoring and review of the safety, radiological, seismic, environmental, and security aspects 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 monitor

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 things, 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 electric 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 Regulators

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 permits, 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 periodically 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 related 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 highways. In exchange for the right to use public streets and highways, 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. Risk 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 Utility'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 expenses). 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 costs 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 proceedings. 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" from 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 2017, the CPUC continued to implement state law requirements to reform residential electric rates to more closely reflect the utilities' actual costs of service, reduce cross-subsidization among customer rate classes, 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 costs, including return on rate base, related to its electric distribution, natural 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 requirements 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 intervenors who represent other business, community, customer, environmental, and union interests. The Utility plans to file the 2020 GRC in the third quarter of 2018. In December 2014, the CPUC established two new procedures concerning safety-related activities, 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 submittal 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 RAMP submittal with the CPUC on November 30, 2017.

(For more information about the Utility's GRC, see "Regulatory Matters –2017 General Rate Case" and "Regulatory Matters –2020 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, the CPUC approves the annual revenue requirements for the first 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 represent 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 capital 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 adjustment 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, see “Regulatory Matters – CPUC Cost of Capital” in Item 7. MD&A.)

Electricity Transmission Owner Rate Cases

The FERC determines the amount of authorized revenue requirements, 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 filed 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 the Utility's retail electric rates and by the CAISO in its Transmission Access Charges to wholesale customers. (For more information, see “Regulatory Matters –Transmission Owner Rate Cases” in Item 7. MD&A.) The Utility also recovers a portion of its revenue 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 charged 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 electrical capacity 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 resources, 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 and 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 costs 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 follow 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 through 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 resource recovery account exceed 5% of its prior year electric procurement and Utility-owned generation revenues. The CPUC performs an annual compliance review of the transactions recorded in the energy resource recovery account.

The CPUC has approved various 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 information, see "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 balancing accounts, with under-collections and over-collections taken into account in subsequent monthly rate changes.

The core procurement incentive mechanism protects the Utility against after-the-fact reasonableness reviews of its gas procurement costs for its 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 natural 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-half 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 retains 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 tariffs 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 pipeline 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 procurement 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 customers, 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 Humboldt 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 decommissioning 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 approval 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, 2018, the CPUC approved the retirement 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 customers 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 will 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 Utility 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 2017 represented by each major electric resource, and further discussed below.

14

Total 2017 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 transmission and distribution related system losses.

Renewable Energy Resources

California law established an 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 entities, including the Utility, to their customers from 33% of their total annual retail sales by the end of the 2017-2020 compliance period, to 50% of their total annual retail sales by the end of the 2028- 2030 compliance period, and in each three-year compliance 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 periods. The Utility will incur additional costs to procure renewable energy to meet the new renewable energy targets, which the Utility expects will continue to be recoverable from customers as "pass-through" costs. The Utility also may be subject to penalties for failure to meet the higher targets. The CPUC is required to open a new rulemaking proceeding to adopt regulations to implement the higher 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 2017, 33.1% of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 27%. Approximately 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 facilities (0.5%).

The total 2017 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 help meet its interim storage targets.

The Utility's 2017 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 three battery storage facilities, each less than 10 MW.

16

Owned Generation Facilities

At December 31, 2017, 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 2024 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 capacity, including agreements for renewable energy resources, in accordance with its CPUC-approved procurement plan. (See “Ratemaking Mechanisms” above.) For more information regarding the Utility’s power purchase agreements, see Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

Electricity Transmission

At December 31, 2017, the Utility owned approximately 19,200 circuit miles of interconnected transmission lines operating at voltages ranging from 60 kV to 500 kV. The Utility also operated 92 electric transmission substations with a capacity of approximately 64,700 MVA. The Utility’s electric transmission system is interconnected with electric power systems in the Western Electricity Coordinating Council, 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, and 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 subsequently 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 longer required and recommended cancelling or requiring further review in the 2017-2018 planning cycle.

Throughout 2017, 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 physical security of its transmission substations and equipment.

Electricity Distribution

The Utility's electric distribution network consists of approximately 107,200 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 59 transmission switching substations, and 605 distribution substations, with a capacity of approximately 31,800 MVA. The Utility's distribution network interconnects with its transmission system, primarily at switching and distribution substations, where equipment reduces the high-voltage transmission 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 facilities in Concord, Rocklin, and Fresno, California; these 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 fault location, isolation, and service restoration 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 continue 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 2015 to 2017 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 2017, 2016 and 2015.

	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 revenues 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 commercial, 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 customers. When the Utility provides both transportation and procurement services, the Utility refers to the combined service as "bundled" natural gas service. Currently, more than 95% of core customers, representing approximately 80% of the annual core market demand, 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 generation 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 distinct 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 2017, the Utility purchased approximately 291,100 MMcf of natural gas (net of the sale of excess 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 during 2017.

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, 2017, the Utility's natural gas system consisted of approximately 42,800 miles of distribution pipelines, over 6,400 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 used 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 for 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 border 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, Oregon, at the California border. Similarly, the Utility has firm transportation agreements with Transwestern Pipeline Company, LLC and El Paso Natural Gas Company to transport natural gas from supply points in the Southwestern United States to interconnection points with the 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 point 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 13 of the Notes to the Consolidated Financial Statements in Item 8.)

20

The Utility owns 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 storage 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 “Regulatory 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 hydrostatically 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 pipelines.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2015 through 2017 (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 2017, 2016 and 2015.

	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 that 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 affirmatively elect to continue to receive electricity generated or procured by a utility.

21

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 Utility 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 for 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 use of customer net energy metering (“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 example, 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 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 customers.

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 facilities within, or interconnected to, its service territory through a competitive bidding process managed by the CAISO. The FERC's transmission planning requirements rules, effective in 2011, removed the incumbent public utility transmission owners' federally-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 CAISO'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 natural 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 other 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 reporting 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, including 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, under 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 Remediation

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 agencies responsible for implementing federal environmental laws. The Utility also must comply with environmental laws and regulations adopted by the State of California 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 and 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 federal, 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 overseen 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 and 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 13 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 operations, 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 the 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 light 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 that 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 to 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 Utility'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 quarterly 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 owners, and farmers) that occur outside of the emitters' facilities through CARB-qualified offset projects such as reforestation or biomass projects. SB 32 (2016) requires that CARB ensure a 40% reduction in greenhouse gases by 2030 compared to 1990 levels. In 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 be passed through to customers. The California RPS program that requires the utilities to gradually increase the amount of renewable energy delivered to their customers is also expected to help reduce GHG emissions in California.

Climate Change Resilience Strategies

During 2017, the Utility continued its programs to mitigate the impact of the Utility's operations (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 levels, major storm events, increasing temperatures 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 infrastructure 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 climate 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 consequences 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 Utility-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 extreme, persistent, and frequent hot weather. The Utility believes its strategies to reduce GHG emissions through energy efficiency and demand response programs, infrastructure improvements, and the use of renewable energy and energy storage are effective strategies for adapting 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, the 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.

Climate scientists predict that climate change will result in varying temperatures and levels 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 such 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 testing 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 volume 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-profit organization. The Utility's third-party verified voluntary GHG inventory reported to The Climate Registry for 2016, the most recent data available, totaled more than 50 million metric tonnes of CO‒2 equivalent, three-quarters of which came from customer natural gas use. The following table shows the 2016 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 CO2)
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) Includes 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 gas delivered to other natural gas local distribution companies.

The following table shows the Utility's third-party-verified CO2 emissions rate associated with the electricity delivered to customers in 2016 as compared to the national average for electric utilities:

	Amount (pounds of CO2 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-Owned 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 2016. 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 SO2	13	17
SO2	0.001	0.001

25

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 technology 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 policy 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 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 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 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, 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 Humboldt 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 other 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 requests 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 claim 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 executed 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.

Given 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 reasonably 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 Department of Insurance issued a press release announcing an update on property losses in connection with the October and December wildfires in California, stating that, as of such date, "insurers have received nearly 45,000 insurance claims totaling more than $11.79 billion in losses," of which approximately $10 billion relates to statewide claims from the October 2017 wildfires. The remaining amount relates to claims from the Southern California December 2017 wildfires. According to the California Department of Insurance, as of the date of the press release, more than 21,000 homes, 3,200 businesses, and more than 6,100 vehicles, watercraft, farm vehicles, and other equipment were damaged or destroyed by the October 2017 wildfires. PG&E Corporation and the Utility have not independently verified these estimates. The California Department of Insurance did not state in its press release whether it intends to provide updated estimates of losses in the future.

If the Utility's facilities are determined to be the cause of one or more of the Northern California wildfires, PG&E Corporation and the Utility could be liable for the related property losses and other damages. The California Department of Insurance January 31, 2018 press release reflects insured property losses only. The press release does not account for uninsured losses, interest, attorneys' fees, fire suppression costs, evacuation costs, medical expenses, personal injury and wrongful death damages or other costs. If the Utility were to be found liable for certain or all of such other costs and expenses, the amount of PG&E Corporation's and the Utility's liability could be higher than the approximately $10 billion 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 the Utility also are the subject 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 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. PG&E Corporation and the Utility expect to be the subject of additional lawsuits in connection with the Northern California wildfires. The wildfire litigation could take a number of years to be resolved because of the complexity of the matters, including the ongoing investigation into the causes of the fires and the growing number of parties and claims involved. The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Northern California wildfires in an aggregate amount of approximately $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 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. (See "If the Utility is unable to recover all or a significant 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 materially 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 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 applicable accounting principles and as described in Note 13 of the Notes to the Consolidated Financial Statements 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 52% 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 financial 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 perception 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 connection with the Butte fire.

In September 2015, a wildfire (known as the "Butte fire") ignited and spread in Amador and Calaveras Counties in Northern California. On April 28, 2016, Cal Fire released its report of the investigation of the origin and cause of the wildfire. According to Cal Fire's report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a gray pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

In connection with the Butte fire, complaints have been filed against the 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 condemnation 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 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 seeking to recover $87 million 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 Calaveras indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $85 million.

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. While this amount includes 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 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 flows. (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 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 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 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.

Additionally, SB 819 introduced in the California Senate in January 2018, if it becomes law, would prohibit utilities' recovery of 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 all or a significant portion of 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 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 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 such undertaking, 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 possible that plaintiffs could be successful in convincing courts to apply this doctrine in these or other litigations. For example, on 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 inverse 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 guarantee 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. In 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.

If 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 wildfires. (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 proceeding 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 corporate 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 community 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 recommendations 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 explosion, 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 interim 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 interests. 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 and other measures, such as a requirement that the Utility's natural gas operations and/or compliance and ethics programs be supervised by one or more independent third-party monitor(s).

The Utility's conviction and the outcome of probation and the debarment 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 affect 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 found 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, regulatory, 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 increasing 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 and 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 market 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 the 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 were 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-speed 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 whether 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 to 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 costs 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 revisit 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 authorized 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 technology, 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 operations, 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 aspects 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, changes in commodity prices also may have an adverse effect on the Utility's ability to timely recover 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 development 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 Requirements

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 Corporation'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 access to the capital markets and availability under their revolving credit facilities and commercial paper programs. PG&E Corporation's and the Utility's ability to access the capital markets, the ability to 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 perception 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 the Utility as needed to maintain the Utility's CPUC-authorized 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 Corporation forecasts it will need a material amount 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, fines 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 programs, 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 adversely 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" obligation to include the requirement that PG&E Corporation "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 Corporation, the Utility 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 Butte 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 Corporation common stock issuances used to fund such equity contributions could materially dilute earnings per share. (See "Liquidity and Financial Resources" in Item 7. MD&A). Further, if PG&E Corporation were required to infuse the Utility with significant capital or if the Utility were 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 suspension 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 Directors 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 on PG&E Corporation's and the Utility's credit ratings and outlook. Their credit ratings and outlook can be affected by many factors, including pending or anticipated litigation, the pending Cal Fire and CPUC investigations and CPUC ratemaking proceedings, 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, Standard & Poor's Global Ratings, each placed all of the ratings of PG&E Corporation and the Utility under review for downgrade, and Standard & Poor's Global 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 investment grade, their ability to access the capital and credit markets would be negatively affected and could result in higher borrowing costs, fewer financing options, including reduced, or lack of, access to the commercial paper market and additional collateral posting requirements, which in turn could affect liquidity and lead to an increased financing need. Other factors can affect the availability and terms of debt and equity financing, including changes in the federal or state regulatory environment affecting energy companies generally or PG&E Corporation and the Utility in particular, the overall health of the energy industry, an increase in interest rates by the Federal Reserve Bank, and general economic and financial market conditions.

The reputations of PG&E Corporation and the Utility continue to suffer from the negative publicity about matters discussed under "Enforcement and Litigation Matters" in 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 Corporation's stock price. Further, the market price of PG&E Corporation common stock could decline materially depending on the outcome of these matters. The amount and timing of future share issuances also could affect the stock price.

Risks Related to Operations 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 "Natural 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 the 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 events;

- 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 electrical 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 employees 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, or 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 third parties that damages 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, including, 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 service, 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 requirements 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 may 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 Utility 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 and 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 operations, 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 the 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 current 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 Utility’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 support 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 deployment 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 things, 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 efficiency programs, energy storage options, EV infrastructure and state infrastructure modernization (e.g. rail and water projects).

37

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 nuclear 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 Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial 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 units 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 of the NRC and urging governmental entities to adopt laws or policies in opposition to nuclear power. Although an action in opposition may ultimately fail, regulatory proceedings may take longer to conclude and be more costly to complete. It is also possible that public pressure could grow leading to adverse changes in legislation, regulations, orders, or their interpretation. As a result, operations at the Utility's two nuclear generation units at Diablo Canyon could cease before their respective licenses expire in 2024 and 2025. In such an instance, the Utility could be required to record a charge for the remaining amount of its unrecovered investment and such charge could have a material effect on PG&E Corporation and the Utility's financial 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 employee 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 recover these costs, PG&E Corporation's and the Utility's financial results could be materially affected. The Utility may determine that it cannot comply with the new regulations or orders in a feasible and economic manner and voluntarily cease operations; alternatively, the NRC may order the Utility to cease operations until the Utility can comply with new regulations, orders, or decisions. The Utility may incur a material charge if it ceases operations at Diablo Canyon's two nuclear generation units before 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 coastal land occupied by the water intake and discharge structures for the nuclear generation units at Diablo Canyon, to run concurrently with Diablo Canyon's current operating licenses. The Utility will be required to obtain an additional lease extension from the State Lands Commission to cover the period of time necessary to decommission the facility. The State Lands Commission and California Coastal Commission will evaluate appropriate environmental mitigation and development conditions associated with the decommissioning project, the costs of which could be substantial.

The Utility also has an obligation to decommission its electricity generation facilities, including its nuclear facilities, as well as gas transmission system assets, at the end of their useful lives. (See Note 2: Summary of Significant Accounting Policies – Asset Retirement Obligations of the Notes to the Consolidated Financial Statement in Item 8.) The CPUC authorizes the Utility to recover its estimated costs to decommission its nuclear facilities through nuclear decommissioning charges that are collected from customers and held in nuclear decommissioning trusts to be used for the eventual decommissioning of each nuclear unit. If the Utility's actual decommissioning costs, including the amounts held in the nuclear decommissioning trusts, exceed estimated costs, PG&E Corporation's and the Utility's financial 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 comply 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, state 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, authorizations, 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 when 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 particular 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 Utility'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 expenditures 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 not 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 condition, 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 compliance 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 and 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 benefits 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 minimum 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. Similarly, 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 assumptions 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 required 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 additional 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 proceedings. 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 affected by events and factors unique to California.

The Utility's business activities are concentrated in Northern California. As a result, the Utility's future performance may be affected by events and economic 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 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" 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

46

		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.

47

PART II

ITEM 5. Market for Registrant’s Common Equity, Related Shareholder Matters and Issuer Purchases of Equity Securities

As of February 1, 2018, 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 years 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 “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 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 during the quarter ended December 31, 2017. PG&E Corporation did not make any sales of unregistered equity securities during 2017 in reliance on an exemption 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 stock outstanding.

48

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 natural 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 reasons, 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 actual 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 with 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 Earnings" 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. Therefore, 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 Notes 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 assess the compliance of electric and communication companies' facilities with applicable rules and regulations in fire impacted areas. According to information made available by the CPUC, investigation topics include, but are not limited to, maintenance of facilities, vegetation management, and emergency preparedness and response. It is uncertain when the investigations will be complete and whether Cal Fire will release any preliminary findings before its investigation is complete.

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

Tax Cuts and Jobs Act of 2017

On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35 percent to 21 percent beginning on January 1, 2018 and eliminated 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 net 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 to 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 materially 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 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 GT&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.

On an aggregate basis, the Utility 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. The estimated benefit to customers 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. Additionally, 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 the 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 available for common shareholders less items impacting comparability. "Items impacting comparability" represent items that management does not consider part of the normal course of operations and affect comparability of financial results between periods. PG&E Corporation uses earnings from operations to understand and compare operating results across reporting periods for various purposes including internal budgeting and forecasting, short and long-term operating plans, and employee incentive compensation. PG&E Corporation believes that earnings from operations provide additional insight into the underlying trends of the business allowing for a better comparison against historical results and expectations for future performance. Earnings from operations are not a substitute or alternative for GAAP measures such as income available for common shareholders and may not be comparable to similarly titled measures used by other companies.

	Three Months Ended December 31,				Year Ended December 31,			
	Earnings		Earnings per Common Share (Diluted)		Earnings		Earnings per Common Share (Diluted)	
(in millions, 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 Corporation's statutory tax rate of 40.75 percent, except as indicated below.

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

(2)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 Tax 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 and compensation-related deferred tax assets.

(3)The Utility incurred 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 $143 million) recorded 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 $37 million) during the three and twelve 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 penalties. 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 gas 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 case 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 Communication 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 months 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 (before the tax impact of $9 million).

(9)As a result of the CPUC's final phase two decision 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 excess of the 2017 authorized revenue requirement, which includes the final component of under-collected revenues retroactive to January 1, 2015.

(10) PG&E Corporation recorded proceeds from insurance, 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 by $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 Key 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 decision 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 ASC 740 and results from variances in the percentage 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 ended 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 million 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. Pursuant 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 base 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 materially affected by the following factors:

- The Impact of the Northern California Wildfires. PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires. The Utility incurred costs of $219 million for service restoration and repairs to the Utility’s facilities (including an estimated $97 million in capital expenditures) in connection with these fires. PG&E Corporation’s and the Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected if the Utility is unable to recover such costs through CEMA. If the Utility’s facilities, such as its electric distribution and transmission lines, are determined to be the cause of one or more fires, and the doctrine of inverse condemnation applies, the Utility could be liable for property damages, interest, and attorneys’ fees without having been found negligent, which liability, in the aggregate, could be substantial. In addition to such claims, as well as claims 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 aggregate, 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 determined 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 13 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. In 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. (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. On December 22, 2017, the U.S. government enacted expansive tax legislation commonly referred to as the Tax Act. Among other provisions, the Tax Act reduces the federal income tax rate from 35 percent to 21 percent beginning on January 1, 2018 and eliminates 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 depreciation. (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 related 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 (retained by the Utility in the first quarter of 2017 as part of its compliance with the sentencing terms of the Utility's January 27, 2017 federal criminal conviction) may make, and potential penalties in connection with the Utility's safety and other self-reports. (See "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 Outcome of Ratemaking Proceedings. The Utility's financial results may be impacted by the timing and outcome 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, potential rate impacts, the Utility's reputation, the regulatory and political environments, and other factors.

- The Ability of the Utility to Control and Recover Operating Costs and Capital Expenditures. In any given year the Utility's ability to earn its authorized rate of return depends on its ability to manage costs within the amounts authorized in rate case decisions. The Utility forecasts that in 2018 it will incur unrecovered pipeline-related expenses ranging from $35 million to $60 million which primarily relate to costs to identify and remove encroachments from transmission pipeline rights-of-way. Also, the CPUC decision in the Utility's 2015 GT&S rate case established various cost caps that will increase the risk of overspend over the rate case cycle through 2018. (See "Disallowance of Plant Costs" in Note 13 of the Notes to the Consolidated 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 Financial Statements, including liabilities, if any, incurred in relation to the Northern California wildfires, adverse effects on PG&E Corporation's and the Utility's ability to comply with consolidated debt to total capitalization ratio covenants in their financing arrangements and regulatory capital structure requirements 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 needed to maintain the Utility's CPUC-authorized capital structure. In 2017, PG&E Corporation issued $416 million 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 provide customers with safe, reliable, and affordable service. The utility industry is also undergoing transformative change driven by technological advancements enabling customer choice (for example, customer-owned generation and energy storage) and state climate policy supporting a decarbonized economy. California's environmental policy objectives are accelerating the pace and scope of the industry change. The electric grid is a critical enabler of the adoption of new energy technologies that support California's climate change and GHG reduction objectives, which continue to be publicly supported by California policy makers notwithstanding a recent change in the federal approach to such matters. In order to enable the California clean energy economy, sustained investments are required in grid modernization, renewable integration projects, energy efficiency programs, energy storage options, EV infrastructure and state infrastructure modernization (e.g. rail and water projects). The Utility forecasts over $1 billion in grid investments through 2020, which would include increased remote control and sensor technology of the grid, integration investments in connection with DER bi-directional energy flows and voltage fluctuations, advanced grid data analytics, grid 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 technological advancements and climate policy may cause a reduction in natural gas usage and increase natural gas costs. The combination of reduced natural gas load and increased costs could result in higher natural gas customer bills and potential cost recovery risk.

For more information about the factors and risks that could affect PG&E Corporation's and the Utility's financial condition, results of operations, liquidity, and cash flows, or that could cause future results to differ from historical results, see Item 1A. Risk Factors. In addition, this 2017 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 "Forward-Looking Statements" below for a list of some of the factors that may cause actual results to differ materially.

PG&E Corporation and the Utility are not able to predict all the factors that may affect future results and do not undertake an obligation to update forward-looking statements, whether in response to new information, future events, or otherwise.

RESULTS OF OPERATIONS

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 provides a summary of net income available 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 authorized to pass through directly to customers (such as costs to purchase electricity and natural gas, as well as costs to fund public purpose programs) and the corresponding amount of revenues collected to recover those pass-through costs, do not impact earnings. In addition, expenses that have been specifically authorized (such as the payment of pension costs) and the corresponding revenues the Utility is authorized to collect to recover such costs, do not impact earnings.

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

57

(in millions)	2017 Revenues and Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	2016 Revenues and Costs: That Impacted Earnings	That Did Not Impact Earnings	Total Utility	2015 Revenues and Costs: 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 million, or 1% in 2017 compared to 2016, primarily due to higher electric transmission revenues.

The Utility's electric and natural 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 additional base revenues as authorized by the CPUC in the 2014 GRC decision and by the FERC in the TO17 rate case.

Operating and Maintenance

The Utility’s operating and maintenance expenses that impacted earnings decreased $675 million, or 12%, in 2017 compared to 2016. In 2017, the Utility incurred $455 million less in disallowed charges (the 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 Penalty Decision and 2015 GT&S rate case decision in 2016) and $447 million less in charges related to the Butte 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). (See 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-related 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 charges 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 2016. 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-party claims related to the San Bruno accident in 2015).

The Utility’s financial condition, results of operations, liquidity, and cash flows could be materially affected by potential losses resulting from the impact of the Northern California wildfires and any additional charges associated with costs related to the Butte fire. (See Item 1A. Risk Factors above and Note 13 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 2017, 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 2016, the increase was primarily due to the impact of capital additions.

Interest 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 2016 compared to 2015, primarily due to the issuance of additional long-term debt.

Interest Income and Other Income, Net

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

Income Tax Provision

The 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 2017 compared to 2016 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 provision 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) Includes 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. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates.

(3) Primarily represents the effects 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 facilities 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.

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

(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 resources 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 to 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
Average 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 2017, 2016, and 2015, 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 Utility suspended quarterly cash dividends on both PG&E Corporation's and the Utility's common stock, beginning the fourth quarter of 2017, as well as the Utility's preferred stock, beginning the three-month period ending January 31, 2018, due to the uncertainty related to the causes of and potential liabilities associated with the Northern California wildfires. (See 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, finance capital expenditures, and make distributions to PG&E Corporation depends on the levels of its operating cash flows and access to the capital and credit markets. The CPUC authorizes the Utility's capital structure, the aggregate amount of long-term and short-term debt that the Utility may issue, and the revenue requirements the Utility is able to collect to recover its cost of capital. The Utility generally utilizes equity contributions from PG&E Corporation and long-term senior unsecured debt issuances to maintain its CPUC-authorized capital structure consisting of 52% equity and 48% debt and preferred stock. (See "Regulatory Matters" in Item 7. MD&A.) The Utility relies on short-term debt, including commercial paper, to fund temporary financing needs.

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

PG&E Corporation's and the Utility's credit ratings may be affected by the ultimate outcome of pending enforcement and litigation matters, including the outcome of the uncertainties and potential liabilities associated with the Northern California wildfires. Credit rating downgrades may increase the cost and availability of short-term borrowing, including commercial paper, the costs associated with credit facilities, and long-term debt costs. In addition, some of the Utility's commodity contracts contain collateral posting provisions tied to the Utility's credit rating from each of the major credit rating agencies. In December 2017, following PG&E Corporation's announcement that it was suspending 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 Investor 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 Notes 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. The Utility'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 described in "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial 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 matters. (See Item 1A. Risk Factors.)

As a result of the Tax Act, the Utility anticipates an annual reduction to revenue requirements of approximately $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 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.

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 unsecured 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 February 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 used 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 $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.

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 twelve 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 issued 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 date 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, 2017, PG&E Corporation and the Utility had an average outstanding 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, 2017, PG&E Corporation and the Utility had outstanding commercial paper balances of $132 million and $50 million, respectively. (See Note 4 of the Notes to the Consolidated Financial Statements in Item 8.)

The revolving credit facilities require that PG&E Corporation and the Utility maintain a ratio of total consolidated debt to total consolidated capitalization of at most 65% as of the end of each fiscal quarter. At December 31, 2017, PG&E Corporation's and the Utility's total consolidated debt to total consolidated capitalization was 50% and 49%, respectively. PG&E Corporation's revolving credit facility agreement also requires that PG&E Corporation owns, directly or indirectly, at least 80% of the common stock and at least 70% of the voting capital stock of the Utility. In addition, the revolving credit facilities include usual and customary provisions regarding events of default and covenants including covenants limiting liens to those permitted under PG&E Corporation's and the Utility's senior note indentures, mergers, and imposing conditions on the sale of all or substantially all of PG&E Corporation's and the Utility's assets and other fundamental changes. At December 31, 2017, PG&E Corporation and the Utility were in compliance with all covenants under their respective revolving credit facilities.

Dividends

The Board of Directors of PG&E Corporation and the Utility 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 Directors. 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 2017, 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 dividend of $2.12 per share. As a result, for the second and third quarters of 2017, 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 quarter 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 $0.49 per share. In 2016, total dividends declared were $1.925 per share. For each of the quarters in 2015, the Board of Directors of PG&E Corporation declared a common stock dividend of $0.455 per share, for annual dividends of $1.82 per share. Dividends paid to common shareholders by PG&E Corporation were $1.0 billion 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 declared 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 paid $14 million of dividends on preferred stock in each of 2017, 2016, and 2015. The Utility's preferred stock is cumulative and any dividends in arrears must be paid before the Utility may 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 case, 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 increased by $597 million compared to 2015. This increase was partially due to the Utility 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 billings and payments.

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

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

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

- the Tax Act, which is expected to accelerate the timing of federal tax payments and reduce revenue requirements, resulting in lower operating cash flows;

- the timing and outcomes 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 not recover, associated with its electric and natural gas systems; 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 increased 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 dependent on the timing and amount of capital expenditures. The Utility estimates that it will incur approximately $6.3 billion in capital expenditures in 2018 and $6.0 billion in 2019.

Financing Activities

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 repayments of $9 million in 2016. During 2016, net cash provided by financing activities decreased by $274 million as compared to 2015. Cash provided by or used in financing activities is driven by the Utility's financing needs, which depend on the level of cash provided by or used in operating activities, the level of cash provided by or used in investing activities, the conditions in the capital markets, and the maturity date of existing debt instruments. The Utility generally utilizes long-term debt issuances and equity contributions from PG&E Corporation to maintain its CPUC-authorized capital structure, and relies on short-term debt to fund temporary financing needs.

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.

REGULATORY MATTERS

The Utility is subject to substantial regulation by the CPUC, the FERC, the NRC, and other federal and state regulatory agencies. The resolutions of these and other proceedings may affect PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

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 Case, 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 GT&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 filings will accelerate that timing. (See "Tax Cuts 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 GRC, which determined the annual amount of base revenues (or "revenue requirements") that the Utility is authorized to collect from customers from 2017 through 2019 to recover its anticipated costs for electric distribution, natural gas distribution, and electric generation operations and to provide the Utility an opportunity to earn its authorized rate of return. The final decision approved, with certain modifications, the settlement agreement that the Utility, the ORA, TURN, and 12 other intervening parties jointly submitted to the CPUC on August 3, 2016 (the "settlement agreement"). 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 income 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.

67

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 revenue requirements and the amounts approved in the final decision:

(in millions)	Amounts Approved in Final Decision (1)	Increase/ (Decrease) 2016 vs. Final Decision
Line of Business:		
Electric distribution	$4,151	$(62)
Gas distribution	1,738	(3)
Electric generation	2,115	153
Total revenue requirements	$8,004	$88
(in millions)		
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 effectiveness study for the SmartMeter™ Upgrade project. On February 8, 2018, the CPUC extended the statutory deadline for the 2017 GRC from February 8, 2018 to August 9, 2018, in order to allow for comments and CPUC action on any PD on the SmartMeterTM 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 application. 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 submittal 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 decisions in phase one and phase two of the Utility's 2015 GT&S rate case. The phase one decision adopted the revenue requirements that the Utility is authorized to collect through rates beginning August 1, 2016, to recover its costs of gas transmission and storage services for the 2015 GT&S rate case period (2015 through 2018). The phase two decision determined the allocation of the $850 million penalty assessed in the San Bruno Penalty Decision and the revenue requirement reduction for the five-month delay caused by the Utility's violation of the CPUC ex parte communication rules in this proceeding.

The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. 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 in 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 decisions, respectively. The Utility cannot predict when or if the CPUC will grant the rehearings or if it will adopt the parties’ recommendations. Additionally, in June 2017, the Utility filed a PFM of the phase one decision to eliminate the requirement that the Utility install new cathodic protection systems in 2018 because the Utility is not in a position to identify the optimal location for such new systems in 2018. Instead, the Utility requested to be allowed to continue its current cathodic protection program. 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 Utility 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 additional year.

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

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

Utility's request is based on capital expenditure forecasts of $971 million for 2019, $963 million for 2020, and $804 million for 2021 (which exclude common capital allocations).

The increase in revenue requirement is largely attributable to increased infrastructure investment and costs related to new natural gas storage safety and environmental regulations. Such new regulations were issued by: (1) the DOGGR, 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 address pipeline safety issues and mandate certain reporting requirements for operators of underground natural gas storage facilities; and (3) the CPUC, which issued General Order 112-F that became effective on January 1, 2017, and requires additional expenditures in the areas of gas leak repair, leak survey, and high consequence area identification, among other things.

In 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 possible 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 Storage Balancing Account to address uncertainty around the anticipated DOGGR regulations, and also proposes a new memorandum account to track costs related to other anticipated new regulations.

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

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.

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

On July 27, 2017, the Utility filed its TO19 rate case at the FERC requesting a 2018 retail electric transmission revenue requirement of $1.79 billion, a $74 million increase over the proposed 2017 revenue requirement of $1.72 billion. The forecasted network transmission rate base for 2018 is $6.9 billion. The Utility is also seeking an ROE of 10.75%, which includes an incentive component of 50 basis points for the Utility’s continuing participation in the CAISO. In the filing, the Utility forecasted capital expenditures of approximately $1.4 billion. On September 28, 2017, the FERC issued an order accepting the Utility’s July 2017 filing, subject to hearing and refund, and established March 1, 2018, as the effective date for rate changes. 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 TO19 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 TO19 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 determined in the TO18 litigation. On October 17, 2017, the Utility answered the complaint, requesting that FERC dismiss it. The Utility is unable to predict when and how the FERC will respond to the complaint.

Transmission Owner Rate Cases for 2015 and 2016 (the “TO16” and “TO17” rate cases)

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 decisions 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 Retirement

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

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

- deferred consideration of replacement resources to the CPUC's Integrated Resource Planning proceeding;
- authorized rate recovery for up to $211.3 million (compared with the $352.1 million requested by the Utility) for an employee retention program;
- authorized rate recovery for an employee retraining program of $11.3 million requested by the Utility;
- rejected rate recovery of the proposed $85 million for the community impacts mitigation program on the ground that rate recovery for such a program requires legislative authorization;
- authorized rate recovery of $18.6 million of the total Diablo Canyon license renewal cost of $53 million and rate recovery of cancelled project costs equal to 100% of direct costs incurred prior to June 30, 2016, and 25% of direct costs incurred after June 30, 2016, based on a settlement agreement among the Utility, the Joint Parties, and certain other parties that the Utility filed with the CPUC in May 2017; and
- approved the amortization of the book value for Diablo Canyon consistent with the Diablo Canyon closure schedule.

During the year ended December 31, 2017, the Utility incurred pre-tax charges of $47 million related to the retirement of Diablo Canyon including $24 million for cancelled projects and $23 million 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.

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

Asset Retirement Obligations

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

While the NDCTP forecast includes employee severance program estimates, it does not include estimated costs related to the final decision's employee retention and retraining and development programs, and the San Luis Obispo County community mitigation program 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 operate 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 existing 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 which 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 memo and ruling issued in the Safety 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%, reflects 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 the 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 Utility filed an application with the CPUC requesting to establish a WEMA to track wildfire expenses and to preserve the opportunity for the Utility to request recovery of wildfire costs in excess of insurance at a future date. Concurrently with this application, the Utility also submitted a motion to the CPUC requesting that the WEMA be deemed effective as of July 26, 2017, such that the Utility may begin recording costs to the account while the application is pending before the CPUC.

Under the WEMA as proposed, the Utility would record costs related to wildfires, including: (1) payments to satisfy wildfire claims, including any deductibles, co-insurance and other insurance expense paid by the Utility but excluding costs that have already been authorized in the Utility's GRC; (2) outside legal costs incurred in the defense of wildfire claims; (3) premium costs not in rates; and (4) the cost of financing these amounts. Insurance proceeds, as well as any payments received from third parties, would be credited to the WEMA as they are received. The WEMA would not include the Utility's costs for fire response and infrastructure costs which are tracked in CEMA. The Utility would be required to file an application to seek approval to recover costs tracked in WEMA. A prehearing conference was held on December 8, 2017, and a scoping memo was issued on January 11, 2018. The Utility filed opening briefs with the CPUC on January 25, 2018 and other parties' briefs are expected to be filed in February 2018. The Utility 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 authorizes the utilities to recover costs incurred in connection with a catastrophic event that has been declared a disaster or state of emergency by competent federal or state authorities. In 2014, the CPUC directed the Utility to perform additional fire prevention and vegetation management work in response to the severe drought in California. The costs associated with this work were tracked in the CEMA. While the Utility believes such costs are recoverable through CEMA, its CEMA applications are subject to CPUC approval.

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 December 2012 through March 2016. On January 4, 2018, ORA, TURN, and the Utility filed an all-party motion with the CPUC seeking approval of a settlement agreement these parties have entered into. The settlement agreement proposes that the Utility's total CEMA 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 Corporation and the Utility 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 proposal is designed to allow energy technologies to be integrated into the larger grid while continuing to provide customers with safe, reliable, and affordable electric service.

On February 27, 2017, the CPUC issued a ruling that seeks the development of a process 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 issued 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, photovoltaic, 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 sourcing 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 submitted 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 grid 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 annual 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 motivating 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 proposal 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 14, 2017, the CPUC approved a final 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 of 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 remaining 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 closely reflect the utilities' actual costs of service, and reduce cross-subsidization 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 associated with legislative and regulatory initiatives, as well as its electricity procurement and other operating costs, will, in large part, depend on the final form of legislative or regulatory requirements, and whether the associated ratemaking mechanisms can be timely adjusted to reflect changes in customer demand for the Utility's electricity and natural gas service.

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 implement 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 customers 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 direct access provider. The Utility projects that more than half of its customers will purchase electricity from a CCA or direct access provider by 2020. Without changes to the current cost allocation system, a portion of the contract and facilities costs will be shifted to customers who remain with the Utility or live in areas that do not have access to alternative electricity providers. The utilities' joint proposed approach would replace the current system, which is known as the PCIA, with an updated system known as the Portfolio Allocation Methodology.

On June 29, 2017, the CPUC dismissed the Utility's joint Portfolio Allocation Methodology application without prejudice and instead approved an OIR to review, revise, and consider alternatives to the PCIA. The OIR will focus on PCIA within the larger context of consumer choice in energy services, 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 scheduled 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 electric 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 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.

On October 11, 2017, the CPUC 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 input 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 CO2 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 as 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, however, 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 price 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, the 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. At 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, the 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 Risk

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 generation 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 electricity 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, and 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 Collateral” in the table below). Credit collateral 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 deemed appropriate by the Utility). Credit collateral 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%
December 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.

77

CRITICAL ACCOUNTING POLICIES

The preparation of the Consolidated Financial Statements in accordance with GAAP involves the use of estimates and assumptions that affect the recorded amounts of assets and liabilities as of the date of the financial statements and the reported amounts of revenues and expenses during 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 outlined below.

Regulatory Accounting

As a regulated entity, the 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 regulatory 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 significant 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 appeals. 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 regulatory 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 that regulatory assets would be recovered 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. If 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 becomes 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 there 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, estimates included in third-party contracts, historical cost experience for similar projects, permitting requirements, environmental compliance standards, and a variety of other factors.

In 2017, the 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 was 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 13 of the Notes to the Consolidated Financial Statements in Item 8.)

Loss Contingencies

As discussed below, PG&E Corporation and the Utility have recorded material accruals for various enforcement and legal matters and environmental 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 named as parties in a number of claims and lawsuits. In addition, penalties may be incurred for failure to comply with federal, state, or local laws and regulations. PG&E Corporation and the Utility record a provision for a loss contingency when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's 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 Litigation 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 the 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 former 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 determine 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 reasonably 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 for 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 time 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 the remediation effort.

At December 31, 2017 and 2016, the Utility's accruals for undiscounted gross environmental liabilities were $1 billion and $958 million, respectively. The Utility's undiscounted future costs could 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 environmental 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 judgments 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 similar 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 Obligations

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 asset retirement costs are capitalized as part of the carrying amount of the related long-lived asset. The Utility recognizes a regulatory asset or liability for the timing differences between the recognition of expenses and costs recovered through the ratemaking 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 estimates and assumptions about 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 employees as well as contributory postretirement health care and medical plans for eligible retirees and their eligible dependents, and non-contributory postretirement life insurance plans for eligible employees and retirees. Adjustments to the pension and other benefit obligation are based on the differences 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 pension benefit expense recognized in accordance with GAAP and amounts recognized for ratemaking purposes are recorded as regulatory assets or liabilities as amounts are probable of recovery from customers. To the extent the other benefits are in an overfunded 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 actuarial assumptions used in determining pension and other benefit obligations include the discount rate, the average rate of future compensation increases, the health care cost trend 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, significant differences in actual experience, plan changes or amendments, or significant changes in assumptions may materially affect the recorded pension and other postretirement benefit obligations and future plan expenses.

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

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

- the 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;

- the 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 the Utility incurs unrecoverable costs that are higher than the forecasts of such costs;

- the timing and outcomes of the 2019 GT&S rate case, TO18 and TO19 rate cases 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 litigation; and whether additional investigations and proceedings in connection with the Butte fire will be opened and any additional fines or penalties imposed on the Utility;

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

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

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

- the effects on PG&E Corporation and the Utility's reputations caused by the Utility's conviction in the federal criminal trial in 2017, the state and federal investigations of natural gas incidents and the Northern California wildfires, improper communications between the CPUC and the Utility, and the Utility's ongoing work to remove encroachments from transmission pipeline rights-of-way;

- whether the Utility can control its costs within the authorized levels of spending, and 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 undergoing 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 additional 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;

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

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

- the amount and timing of additional common stock and debt issuances by PG&E Corporation, including the dilutive impact of common stock issuances to fund PG&E Corporation's equity contributions to the Utility as the Utility incurs charges and costs, including fines, that it cannot recover through rates;

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

- the outcome of current and future self-reports, investigations or other enforcement proceedings that could be commenced or notices of violation that could be issued relating to the Utility's compliance with laws, rules, regulations, or orders applicable to its operations, including the construction, expansion or replacement of its electric and gas facilities, electric grid reliability, inspection and maintenance practices, customer billing and privacy, physical and cyber security, environmental 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 SmartMeter™ Upgrade cost-benefit analysis, and of the Utility's PFMs, including in connection 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; and the extent to which the Utility is able to recover environmental costs in rates or from other sources;

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

83

- 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 programs for Diablo Canyon employees as a result of its planned retirement by 2024 and 2025;

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

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

- how the CPUC and the CARB implement state environmental laws relating to GHG, renewable energy targets, energy efficiency standards, DERs, EVs, and similar matters, including whether the Utility is able to continue recovering associated compliance costs, such as the cost of emission allowances and offsets under cap-and-trade regulations; and whether the Utility is able to timely recover its associated investment costs;

- whether the Utility’s climate change adaptation strategies are successful;

- the impact that reductions in customer demand for electricity and natural gas have on the Utility’s ability to make and recover its investments through rates and earn its authorized return on equity, and whether the Utility is successful in addressing the impact of growing distributed and renewable generation resources, changing customer demand for natural gas and electric services, and an increasing number of customers departing the Utility’s procurement service for CCAs;

- the supply and price of electricity, natural gas, and nuclear fuel; the extent to which the Utility can manage and respond to the volatility of energy commodity prices; the ability of the Utility and its counterparties to post or return collateral in connection with price risk management activities; and whether the Utility is able to recover timely its electric generation and energy commodity costs through rates, including its renewable energy procurement costs;

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

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

- changes in credit ratings which could, 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 interpretation, on energy policy and the regulation of utilities and their holding companies, including how the CPUC interprets and enforces the financial and other conditions imposed on PG&E Corporation when it became the Utility's holding company, and whether the ultimate outcomes of the CPUC's pending investigations, the 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 changes 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 flows, 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, future events, or otherwise.

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

ITEM 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.

85

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 Corporation

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.

89

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

90

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.

91

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.

92

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.

94

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.

98

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
Equity contribution	-	-	455	-	-	455
Common stock dividend	-	-	-	(784)	-	(784)
Preferred 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 receivable 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. The Utility's ability to recover revenue 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 Utility recognizes revenues that have been authorized for rate recovery, are objectively determinable and probable of recovery, and are expected to be collected within 24 months. Generally, revenue is recognized ratably over the year. The Utility records a balancing account asset or liability for differences between customer billings and authorized revenue requirements that are probable of recovery or refund.

The CPUC also has authorized the Utility to collect additional revenue requirements to recover costs that the Utility has been authorized to pass on to customers, including costs to purchase electricity and natural gas; and to fund public purpose, demand response, and customer energy efficiency programs. In general, the revenue recognition criteria for pass-through costs billed to customers are met at the time the costs are incurred. The Utility records a regulatory balancing account asset or liability for differences between incurred costs and customer billings or authorized revenue meant to recover those costs, to the extent that these differences are probable of recovery or refund. 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 to recover revenue requirements authorized by the FERC is dependent on the volume of the Utility's electricity sales, and revenue is recognized only for amounts billed and unbilled, net of revenues subject to refund.

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. 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, current 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 distribution 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 appropriate, 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 – other 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 depreciation 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:

	Estimated Useful	Balance at December 31,	
(in millions, except estimated useful lives)	Lives (years)	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 composite depreciation 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 future 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 activities and minor replacements of property, is charged to operating and maintenance expense as incurred.

AFUDC

AFUDC represents the estimated costs 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 recorded 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 million 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 expected to operate in perpetuity. As the Utility cannot estimate a settlement date or range of potential settlement dates for these assets, reasonable estimates of fair value cannot be made. As such, ARO liabilities are not recorded for retirement activities 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 of land to specified conditions under certain 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 NDCTP. 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 Utility'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 Diablo 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 NDCTP. The CPUC's final decision resulted in a $66 million 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 estimated 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 Decommissioning 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 facility 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. The Utility's nuclear decommissioning costs are recovered from customers through rates and are held in trusts until authorized for release by the CPUC.

The Utility classifies its investments held in the nuclear decommissioning trusts as "available-for-sale." Since the Utility's nuclear decommissioning trust assets are managed by external investment 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 refundable 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 comprehensive 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 subordinated financial support from other parties, or whose equity investors lack any characteristics of a controlling financial interest. An enterprise that has a controlling financial interest in a VIE is a primary beneficiary and is required to consolidate the VIE.

Some of the counterparties to the Utility's power purchase agreements are considered VIEs. Each of these VIEs was designed to own a power plant that would generate electricity for sale to the Utility. To determine whether the Utility was the primary beneficiary of any of these VIEs at 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. The Utility's financial obligation is limited to the amount the Utility pays for delivered electricity and capacity. The Utility did not have any decision-making rights associated with any of the activities that are most significant to the economic performance of any of these VIEs. Since the Utility was not the primary beneficiary of any of these VIEs at 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 and 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.)

104

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.

105

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 post-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 addition, 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 component 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 about leasing arrangements. In November, 2017, the FASB tentatively decided to amend the new leasing guidance such that entities may elect not to restate their comparative periods in the period of adoption. Under the new standard, all lessees must recognize an asset and liability on the balance sheet. Operating leases were previously not recognized on the balance sheet. The ASU will be effective for PG&E Corporation and the Utility on January 1, 2019, with early adoption permitted. PG&E Corporation and the Utility plan to adopt this guidance in the first quarter of 2019. PG&E Corporation and the Utility expect this standard to increase lease assets and lease liabilities on the Consolidated Balance Sheets and do not expect the guidance will have a material 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 – Overall (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 equity investments (excluding those accounted for under the equity method or those that result in consolidation) to be measured at fair value, with changes in fair value recognized in net income. The majority of PG&E Corporation's and the Utility's investments are held in the nuclear decommissioning trusts. 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 the Utility on January 1, 2018 and will not have a material impact on the Consolidated Financial Statements and related disclosures.

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 capital 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 balancing 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 prevention and vegetation management. Current 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) recognized 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 these 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 annual contribution requirements. As these annual requirements continue indefinitely into the future, the 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 liability 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 recovering 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 unamortized loss, net of gain, on reacquired debt.

Regulatory Liabilities

Long-Term Regulatory Liabilities

Long-term regulatory liabilities are comprised of the following:

	Balance at December 31,	
(in millions)	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 on these 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 related 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 period 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 accounts will fluctuate during the year based on seasonal electric and gas usage and the timing of when costs are incurred and customer revenues are collected.

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

	Receivable Balance at 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. Public purpose programs balancing accounts are primarily used to record and recover authorized revenue requirements for commission-mandated programs such as energy efficiency.

NOTE 4: DEBT

Long-Term Debt

The following table summarizes PG&E Corporation’s and the Utility’s long-term debt:

		December 31,	
(in millions)		2017	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 of 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 December 1, 2020. 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 without 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 Geysers Power Company, LLC pursuant to purchase and sales 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 the 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, the Utility has no knowledge that Geysers Power Company, LLC intends to cease using the bond-financed 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 rate	-	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. Although 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 credit facilities and commercial paper programs 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 $500 million 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 outstanding 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 the Utility in 2017.

Revolving Credit Facilities

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. PG&E Corporation's and the Utility's revolving credit facilities may be used for working capital, the repayment of commercial paper, and other 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. The 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 revolving 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 owns, 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 Programs

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, respectively. PG&E Corporation and the Utility treat the amount of outstanding commercial paper as a reduction to the amount available under their respective revolving credit facilities. The commercial paper may have maturities up to 365 days and ranks equally 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 Corporation and Utility commercial paper was 1.29% and 1.11%, respectively.

Other Short-term Borrowings

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 unsecured term loan maturing on February 22, 2018. 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 $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 COMPENSATION

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, 2017.

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 respective 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 Corporation'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 quarterly 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" in 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 17 million shares of PG&E Corporation common stock (subject to certain adjustments) has been reserved for issuance under the 2014 LTIP, of which 14,327,157 shares were available for future awards 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 share-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

Restricted stock units generally vest equally over three years. Vested restricted stock units are settled in shares of PG&E Corporation common stock accompanied by cash payments to settle any dividend 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 granted 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, forfeitures are recorded rateably over the vesting period, using historical averages and adjusted to actuals when vesting occurs. As of December 31, 2017, $33 million of total unrecognized compensation costs related to nonvested restricted stock units was expected to be recognized over the remaining weighted average period of 1.46 years.

112

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 Corporation 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 of 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, respectively. There was no tax benefit associated with performance shares during each of these periods. In general, forfeitures 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 years.

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 of 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.

113

At December 31, 2017, annual dividends on the Utility's nonredeemable preferred 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 dividends on redeemable preferred stock ranged from $1.09 to $1.25 per share.

On December 20, 2017, the Boards of Directors of PG&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 wildfires. 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. The 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 and weighted average common shares outstanding for calculating diluted EPS for 2017, 2016, and 2015.

	Year Ended December 31,		
(in millions, 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
Total 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 income 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 expense.

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. The 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, the difference between a tax position taken or expected to be taken in a tax 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 amortizes 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. federal 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 agreement 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
Deferred:						
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)

115

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
Deferred 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 for 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 generation repairs deductions.

(2) Includes 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. Therefore, PG&E Corporation's and the Utility's effective tax rates are impacted as these differences arise and reverse. PG&E Corporation and the Utility recognize such differences as regulatory assets or liabilities as it is probable that these amounts will be recovered from or returned to customers in future rates.

116

(3) Primarily represents the effects 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 facilities 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 Benefits

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 during a prior year	(71)	(77)	(349)	(71)	(77)	(349)
Additions for tax position taken during the current year	48	56	64	48	56	64
Settlements	(14)	(59)	-	(8)	(59)	-
Expiration of statute	(3)	-	-	(3)	-	-
Balance at end of year	$349	$388	$468	$349	$382	$462

The component of unrecognized 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 Income. For the years ended December 31, 2017, 2016, and 2015, 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 provisions, 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 income 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 the SEC in Staff Accounting 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 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 to a net regulatory liability. The 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 differ from the above recorded amounts, possibly materially, due to, among other things, 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. 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 Staff 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 Taxation 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 followed 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 clarifies 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 decision 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 to 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 allowed 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 requirements. 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 losses, charitable contributions and tax credits can be realized within the carryforward periods, therefore no valuation allowance was recognized as of December 31, 2017 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 volatility 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 fair value and on a net basis in accordance with master netting arrangements for each counterparty. The fair value of derivative instruments is further offset by cash collateral paid or received where the right of offset and the intention to offset exist.

Price risk management activities that meet the definition of derivatives are recorded at fair value on the Consolidated Balance Sheets. These instruments are not held for speculative purposes and are subject to certain regulatory requirements. The Utility expects to fully recover in rates all costs related to derivatives under the applicable ratemaking mechanism in place as long as the Utility's price risk management activities are carried out in accordance with CPUC directives. Therefore, all unrealized gains and losses associated with the change in fair value of these derivatives are deferred and recorded within the Utility's regulatory assets and liabilities on the Consolidated Balance Sheets. Net realized gains or losses on commodity derivatives are recorded in the cost of electricity or the cost of natural gas with corresponding increases or decreases to regulatory balancing accounts for recovery from or refund to customers.

The Utility elects the normal purchase and sale exception for eligible derivatives. Eligible derivatives are those that require physical delivery in quantities that are expected to be used by the Utility over a reasonable period in the normal course of business, and do not contain pricing provisions unrelated to the commodity delivered. These items are not reflected in the 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 volumes of the Utility's outstanding derivatives were 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

119

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 in 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.

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

(in millions)	Balance at December 31, 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 credit 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 established that prioritizes the inputs to valuation methodologies used to measure fair value:

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

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

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

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

Assets and liabilities measured at fair value on a recurring basis for PG&E Corporation and the Utility are summarized below. Assets held in rabbi trusts are held by PG&E Corporation and not the Utility.

	Fair Value Measurements 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 deducting $440 million, primarily related to deferred taxes on appreciation of investment value.

(in millions)	Fair Value Measurements At December 31, 2016 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.

Valuation Techniques

The following describes the valuation techniques used to measure the fair value of the assets and liabilities shown in the tables above. There are no restrictions on the terms and conditions upon which the investments may be redeemed.

Transfers between levels in the fair value hierarchy are recognized as of the end of the reporting period. There were no material transfers between any levels for the 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. Nuclear decommissioning trust assets and other trust assets are composed primarily of equity and fixed-income securities and also include short-term investments that are money market funds valued at Level 1.

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

Fixed-income securities are primarily composed of U.S. government and agency securities, municipal securities, and other fixed-income securities, including corporate debt securities. U.S. government and agency securities primarily consist of U.S. Treasury securities that are classified as Level 1 because the fair value is determined by observable market prices in active markets. A market approach is generally used to estimate the fair value of fixed-income securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

Assets Measured at NAV Using Practical Expedient

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

Price Risk Management Instruments

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

Power purchase agreements, forwards, and swaps are valued using a discounted cash flow model. Exchange-traded futures that are valued using observable market forward prices for the underlying commodity are classified as Level 1. Over-the-counter forwards and swaps that are identical to exchange-traded futures, or are valued using forward prices from broker quotes that are corroborated with market data are classified as Level 2. Exchange-traded 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 management utilizes models to derive pricing inputs for the valuation of the Utility's Level 3 instruments using pricing inputs from brokers and historical data.

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

Level 3 Measurements and Sensitivity Analysis

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

Significant increases or decreases in any of those inputs would result in a significantly higher or lower fair value, respectively. All reasonable costs related to Level 3 instruments are expected to be recoverable through customer rates; therefore, there is no impact to net income resulting from changes in the fair value of these instruments. (See Note 9 above.)

(in millions)	Fair Value at At December 31, 2017		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	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. (1) Represents price per megawatt-hour

(in millions)	Fair Value at At December 31, 2016		Valuation	Unobservable	
Fair Value Measurement	Assets	Liabilities	Technique	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, unrealized gains and losses are deferred in regulatory liabilities and assets and net income is not impacted.

Financial Instruments

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

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

- The fair values of the Utility’s fixed-rate senior notes and fixed-rate pollution control bonds and PG&E Corporation’s fixed-rate senior notes were based on quoted market prices at 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 values):

	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

125

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:

	2017	2016	2015

(in millions)			
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”). The trusts underlying certain of these plans are qualified trusts under the Internal 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 Utility 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.

127

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 Consolidated 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 expense 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 Income 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 benefits, 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 that 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 will be amortized into net periodic benefit costs 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 periodic 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 costs. The following weighted average year-end assumptions were used in determining the plans' projected benefit obligations and net 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 an ultimate 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-Point 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 plan 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 added 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 other benefits 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 discount 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 funded status occurs when 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. PG&E Corporation'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, interest 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 trusts hold significant allocations in long maturity fixed-income investments. Although they contribute 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 investments by exhibiting returns with low correlation to the direction of these markets. Real 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. Foreign 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 and 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 appropriate 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, respectively, 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 table 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 includes 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 markets 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 public 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 fair value of debt securities classified as Level 2 using evaluated pricing data such as broker quotes, for similar securities adjusted for observable differences. Significant inputs used in the valuation model generally include benchmark yield curves and issuer spreads. The external credit ratings, coupon rate, and maturity of each security are considered in the valuation model, as applicable.

Assets Measured at NAV Using Practical Expedient

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 investments include commingled funds that are composed of equity securities traded publicly on exchanges as well as fixed-income securities that are composed primarily of U.S. government securities, asset-backed securities, and private real estate funds. There 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 end of the reporting period. No material transfers 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 plan that have been classified as Level 3 for the years ended December 31, 2017 and 2016:

(in millions) 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) 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 Corporation and the Utility contributed $335 million to the pension benefit plans and $33 million 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 decisions 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 requirements 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 received 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 to make pre-tax and after-tax contributions 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 material 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 generally 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 accounting 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 receivables of $20 million and $18 million, respectively, from PG&E Corporation included in accounts receivable – other and other noncurrent assets – other on the Utility's Consolidated Balance Sheets, and payables 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 Corporation and the Utility have significant contingencies arising from their operations, including contingencies related to enforcement and litigation matters and environmental remediation. A provision for a loss contingency is recorded when it is both probable that a loss has been incurred and the amount of the loss can be reasonably estimated. PG&E Corporation and the Utility evaluate the range of reasonably estimated losses and record a provision based on the lower end of the range, unless an amount within the range is a better estimate than any other amount. The assessment of whether a loss is probable or reasonably possible, and whether the loss or a range of loss is estimable, often involves a series of complex judgments about future events. Loss contingencies are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, such as negotiations, discovery, settlements and payments, rulings, advice of legal counsel, and other information and events pertaining to a particular matter. PG&E Corporation's and the Utility's 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 support 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 materially affected by the outcome of the following matters.

Enforcement and Litigation Matters

Northern California Wildfires

Beginning on October 8, 2017, multiple wildfires spread through Northern California, including Napa, Sonoma, Butte, Humboldt, Mendocino, Del Norte, Lake, Nevada, and Yuba Counties, as well as in the area surrounding Yuba City. According to the Cal Fire California Statewide Fire Summary dated October 30, 2017, at the peak of the wildfires, there were 21 major wildfires in 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. California courts have imposed liability under the doctrine of inverse condemnation in legal actions brought by property holders against utilities on the grounds that losses borne by the person whose property was damaged through a public use undertaking should be spread across the community that benefitted from such undertaking and based on the assumption that utilities have the ability to recover these costs from their customers. Further, courts could determine that the doctrine of inverse condemnation applies even in the absence of an open CPUC proceeding for cost recovery, or before a potential cost recovery decision is issued by the CPUC. There is no guarantee that the CPUC would authorize cost recovery even if a court decision were to determine that the doctrine of inverse condemnation applies. In addition to such claims for property damage, interest and attorneys' fees, the Utility could be liable for fire suppression costs, evacuation costs, medical expenses, personal injury damages, and other damages under other theories of liability, including if the Utility were found to have been negligent, which liability, in the aggregate, could be substantial and have a material adverse effect on PG&E Corporation and the Utility. Further, the Utility could be subject to material fines or penalties if the CPUC or any other law enforcement agency brought an enforcement action and determined that the Utility failed to comply with applicable laws and regulations.

Given the 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 reasonably 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 Department of Insurance issued a press release announcing an update on property losses in connection with the October and December wildfires in California, stating that, as of such date, "insurers have received nearly 45,000 insurance claims totaling more than $11.79 billion in losses," of which approximately $10 billion relates to statewide claims from the October 2017 wildfires. The remaining amount relates to claims from the Southern California December 2017 wildfires. According to the California Department of Insurance, as of the date of the press release, more than 21,000 homes, 3,200 businesses, and more than 6,100 vehicles, watercraft, farm vehicles, and other equipment were damaged or destroyed by the October 2017 wildfires. PG&E Corporation and the Utility have not independently verified these estimates. The California Department of Insurance did not state in its press release whether it intends to provide updated estimates of losses in the future.

If the Utility's facilities are determined to be the cause of one or more of the Northern California wildfires, PG&E Corporation and the Utility could be liable for the related property losses and other damages. The California Department of Insurance January 31, 2018 press release reflects insured property losses only. The press release does not account for uninsured losses, interest, attorneys' fees, fire suppression costs, evacuation costs, medical expenses, personal injury and wrongful death damages or other costs. If the Utility were to be found liable for certain or all of such other costs and expenses, the amount of PG&E Corporation's and the Utility's liability could be higher than the approximately $10 billion 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.

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 actions, that have been filed against PG&E Corporation and the Utility in the Sonoma, Napa and San Francisco Counties Superior Courts. The lawsuits allege, among other things, negligence, inverse condemnation, trespass, and private nuisance. They principally assert that PG&E Corporation's and the Utility's alleged failure to maintain and repair their distribution and transmission lines and failure to properly maintain the vegetation surrounding such lines were the causes of the fires. The plaintiffs seek damages that include wrongful death, personal injury, property damage, evacuation costs, medical expenses, punitive damages, attorneys' fees, and other damages. In addition, insurance carriers who have made payments to their insureds for property damage arising out of the fires have filed 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 and the Utility submitted a petition for coordination to the Chair of the Judicial Council of California, and requested separate coordination in the counties in which the fires occurred. On January 4, 2018, the coordination motion judge of the San Francisco Superior Court entered an order granting coordination of the litigation in connection with the Northern California wildfires and recommending that the coordinated proceeding take place in the San Francisco Superior Court. On January 12, 2018, the Judicial Council of California accepted the coordination motion judge's recommendation and assigned the coordinated proceeding to San Francisco. The first case management conference 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 Corporation 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 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. 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 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 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 report, the fire burned 70,868 acres, resulted in two fatalities, destroyed 549 homes, 368 outbuildings and four commercial properties, and damaged 44 structures. Cal Fire's report concluded that the wildfire was caused when a gray pine tree contacted the Utility's electric line which ignited portions of the tree, and determined that the failure by the Utility and/or its vegetation management contractors, ACRT Inc. and Trees, Inc., to identify certain potential hazards during its vegetation management program ultimately led to the failure of the tree.

Third-Party Claims

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its two vegetation management contractors in the Superior Court of California 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 31, 2017, 77 known complaints have been filed against the Utility and its two vegetation management contractors in the Superior Court of California in the Counties of Calaveras, San Francisco, Sacramento, and Amador. The complaints involve approximately 3,770 individual plaintiffs representing approximately 2,030 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 doctrine of inverse condemnation and negligence theory 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 that 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 engaged in a mediation process.

Further, in May 2017, the OES indicated that it intends to bring a claim against the Utility that it estimates in the approximate amount of $190 million. This claim would include costs incurred by the OES for tree and debris removal, infrastructure damage, erosion control, and other claims related to the Butte fire. Also, 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 million. 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 conscious disregard for public safety based on the fact that the Utility relied on contractors to fulfill their contractual obligation to hire and train qualified employees. On August 16, 2017, the Utility filed a writ with the Court of Appeals challenging what 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 inverse condemnation applies to the Utility with respect to the Butte fire. The court held, among other things, that the Utility had failed to put forth any evidence to support its contention that the CPUC would not allow the Utility to pass on its inverse condemnation liability through rate increases. While the ruling is binding only between the Utility and the plaintiffs in the coordination proceeding, others could file lawsuits and make similar claims. On January 4, 2018, the Utility filed with the court a renewed motion for a legal determination of inverse condemnation liability, citing the November 30, 2017 CPUC decision denying the San Diego Gas & Electric Company application to recover wildfire costs in excess of insurance, and the CPUC declaration that it will not automatically allow utilities to spread inverse condemnation losses through rate increases. 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 trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and certain other damages, but does not include punitive damages for which the Utility could be liable. In addition, while this amount includes the Utility's 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 sufficient 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 claims relating to the Butte fire requires management to exercise significant judgment based on a number of assumptions and subjective factors. As more information becomes known, including additional discovery from the plaintiffs, results from the ongoing mediation and settlement process, review of 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 estimates and assumptions regarding the financial impact of the Butte fire may result in material increases to the loss accrued.

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

138

Loss Recoveries

The Utility has liability insurance from various insurers, which provides coverage for third-party liability attributable to the Butte fire in an aggregate amount of $922 million. The Utility records insurance recoveries when it is deemed probable that a recovery will occur and the Utility can reasonably estimate the amount or its range. Through December 31, 2017, the Utility recorded $922 million for probable insurance recoveries in connection with losses related to the Butte fire. While the Utility plans to seek recovery of all insured losses, it is unable to predict the ultimate amount and timing of such insurance recoveries. In addition, in the year ended December 31, 2017, the Utility received $53 million of reimbursements from the insurance policies of one of its vegetation management contractors (excluded from the table below). Recoveries of additional amounts under the insurance policies of the Utility's vegetation management contractors, including policies where the Utility is listed as an additional insured, are uncertain.

The following table presents changes in the insurance receivable since December 31, 2015. The balance for the insurance receivable is included in Other accounts receivable in PG&E Corporation's and the Utility's 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 affected 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, 2017, the SED issued two citations to the Utility in connection with the Butte fire, totaling $8.3 million. The SED's investigation found that neither the Utility nor its vegetation management contractors took appropriate steps to prevent 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.

Enforcement Matters

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

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 CPUC. Ex parte communications include communications between a decision maker or a commissioner's advisor and interested persons concerning substantive issues in certain formal proceedings. Certain communications are prohibited and others are permissible with proper noticing and reporting.

On November 23, 2015, the CPUC issued an OII into whether the Utility should be sanctioned for violating rules pertaining to ex parte communications and Rule 1.1 of the CPUC's Rules of Practice and Procedure governing the conduct of those appearing before the CPUC. The OII cites some of the communications the Utility reported to the CPUC. The OII also cites the ex parte violations alleged in the City of San Bruno's July 2014 motion, which it filed in CPUC investigations 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 with 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 million 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 total amount of $12 million ($6 million to each city). In addition, the settlement agreement provides for certain non-financial remedies, including enhanced noticing obligations between the Utility and CPUC decision-makers, as well as certification of employee training on the CPUC ex parte communication rules. Under the terms of the settlement agreement, customers will bear no costs associated with the financial remedies set forth above.

On September 21, 2017, the Utility submitted a motion to the CPUC accepting 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 raise 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 agreement 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 extending 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 California 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 set forth the scope and timing of remedial work to remove identified encroachments over a multi-year period and to pay penalties if the proposed milestones were not met. In March 2014, the Utility informed the SED that the survey had been completed and that remediation work, including removal of the encroachments, was expected to continue for several years. The SED has not addressed the Utility's proposed compliance plan, and it is reasonably possible that the SED will impose fines on the Utility in the future based on the Utility's failure to continuously survey its system and remove encroachments. The Utility is unable to reasonably estimate the amount or range of future charges that could be incurred given the SED's wide discretion and the number of factors that can be considered in determining penalties.

Potential Safety Citations

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

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. In the past, the SED has imposed fines on the Utility ranging from $50,000 to $16.8 million for violations of electric and natural gas laws and regulations. The CPUC can also open an OII and levy additional fines even after the SED has issued a citation.

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

Other Matters

Other Contingencies

PG&E Corporation and the Utility are subject to various claims, lawsuits and regulatory proceedings that separately are not considered material. Accruals for contingencies related to such matters (excluding amounts related to the contingencies discussed above under "Enforcement and Litigation Matters") totaled $86 million at December 31, 2017 and $45 million at December 31, 2016. These amounts are included in Other 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 disallowances 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 Utility's 2015 GT&S rate case. The phase one decision excluded from rate base $696 million of capital spending in 2011 through 2014 in excess of the amount adopted. The decision permanently disallowed $120 million of that amount and ordered that the remaining $576 million be subject to an audit overseen by the CPUC staff, with the possibility that the Utility may seek recovery in a future proceeding. The decision also established various cost caps that will increase the risk of overspend over the current rate 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 decision. 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 based on the Utility's ability to manage its capital spending and on the outcome of the CPUC's audit of 2011 through 2014 capital spending.

Capital 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, the 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 to exceed the authorized amount. The Utility expects the remaining PSEP work to continue 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 Diablo 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 application 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, the 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.

Environmental 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 estimating remediation liabilities requires significant judgment. The Utility records an environmental remediation liability when 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 probable 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 and maintenance 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 primarily 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 storage, 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 quality 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 remediation. The Utility may incur actual costs in the future that are materially different than this estimate and such costs could have a material impact on results of operations, financial condition and cash flows during the period in which they are recorded. At December 31, 2017, the Utility expected to recover $725 million of its environmental remediation liability through various ratemaking mechanisms authorized by the CPUC.

Natural Gas Compressor Station Sites

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

Topock Site

The Utility's remediation and abatement efforts at the Topock site are subject to the regulatory authority of the DTSC and the DOI. In November 2015, the Utility submitted its final remediation design to the agencies for approval. The Utility's design proposes that the Utility construct an in-situ groundwater treatment system to convert hexavalent chromium into a non-toxic and non-soluble form of chromium. On December 21, 2017 the DTSC issued its final environmental impact report. The environmental impact report includes requirements related to conditions of work that have been anticipated or previously required and are accounted for in the current environmental remediation liability. The Utility's undiscounted future costs associated with the Topock site may increase by as much as $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 implementing 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 regulatory authority of the California Regional Water Quality Control Board, Lahontan Region. In November 2015, the California Regional Water Quality Control Board, Lahontan Region adopted a final clean-up and abatement order to contain and remediate the underground plume of hexavalent chromium and the potential environmental impacts. The final order states that the Utility must continue and improve its remediation efforts, define the boundaries of the chromium plume, and take other action. Additionally, the final order requires setting plume capture requirements, requires establishing a monitoring and reporting program, and finalizes deadlines for the Utility to meet interim cleanup targets. The 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. The costs associated with environmental remediation at the Hinkley site will not be recovered through rates.

Former Manufactured Gas Plants ("MGPs")

Former manufactured 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.

Utility-Owned Generation Facilities and Third-Party Disposal Sites

Utility-owned generation facilities and third-party disposal sites are long-term projects that are undergoing a remediation process. The Utility's undiscounted future costs associated with Utility-owned generation facilities and third-party disposal sites may increase by as much as $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 plant business as part of generation deregulation. Although the Utility has sold its fossil-fueled power plants, the Utility has retained the environmental remediation liability associated with each site. The Utility's undiscounted future costs associated with fossil fuel-fired generation sites may increase by as much as $106 million if the extent of contamination or necessary remediation is greater than anticipated. The environmental remediation costs associated with the fossil fuel-fired sites will not be recovered through rates.

Nuclear Insurance

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

If NEIL losses in any policy year exceed accumulated funds, the Utility could be subject to a retrospective assessment. If NEIL were to exercise this assessment, as of December 31, 2017, the current maximum aggregate annual retrospective 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 policy 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 incidents 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 maximum 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 liability 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 between May 2000 and June 2001. While the FERC and judicial proceedings are pending, the Utility has pursued, and continues to pursue, settlements with electricity suppliers. The Utility has entered into a number of settlement agreements with various electricity suppliers to resolve some of these disputed claims and to resolve the Utility's refund claims against these electricity suppliers. Under these settlement agreements, amounts payable by the parties are, in some instances, subject to adjustment based on the outcome of the various refund offset and interest issues being considered by the FERC. Generally, any net refunds, claim offsets, or other credits that the Utility receives from electricity suppliers either through settlement or through the conclusion of the various FERC and judicial proceedings are refunded to customers through rates in future periods.

At December 31, 2017 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 payment obligations for natural gas supplies, natural gas transportation, natural gas storage, and nuclear fuel as of December 31, 2017:

	Power Purchase Agreements					
	Renewable	Conventional		Natural	Nuclear	
(in millions)	Energy	Energy	Other	Gas	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

145

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 electricity at the date of delivery.

Renewable Energy Power Purchase Agreements. In order to comply with California'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 Utility'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 between 2018 and 2043.

Conventional Energy Power Purchase Agreements. The Utility has entered into power purchase agreements for conventional generation resources, which include tolling agreements and resource adequacy agreements. The Utility's obligation under a portion of these agreements is contingent on the third parties' development of new generation facilities to provide capacity and energy products to the Utility. As of December 31, 2017, these power purchase agreements expire at various dates between 2018 and 2033.

Other Power Purchase Agreements. The Utility has entered into agreements 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 million, 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, the Utility has agreements with various irrigation districts and water agencies to purchase hydroelectric power.

The costs incurred for all power purchases 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 contracted 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 gas storage, which include contracts with terms of less than 1 year, amounted to $0.9 billion in 2017, $0.7 billion in 2016, and $0.9 billion in 2015.

146

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-term nuclear fuel supply. The 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 million in 2017, $100 million in 2016, and $128 million in 2015.

Other Commitments

PG&E Corporation and the Utility have other commitments related to operating leases (primarily office facilities and land), which expire at various dates between 2018 and 2052. At December 31, 2017, the future minimum payments related to these commitments were as follows:

(in millions)	Operating Leases
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 rentals 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.

147

QUARTERLY CONSOLIDATED FINANCIAL DATA (UNAUDITED)

(in millions, except per share amounts)	Quarter ended 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 operating 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 2016, 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 for 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, the 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 insurance 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 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 Company and our report 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 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 Commission 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 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 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 generally 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 and 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 expenditures 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 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 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 Treadway 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 report 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 Northern 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 Internal 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 standards 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 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 generally 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 and 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 expenditures 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 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 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

PG&E Corporation

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of PG&E Corporation and subsidiaries (the "Company") as of December 31, 2017 and 2016, the Company's related consolidated statements 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 statements"). 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 ended 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 Oversight 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 Treadway 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 responsibility 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 securities 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 reasonable 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 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 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.

153

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, comprehensive 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 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 Oversight Board (United States) (PCAOB), 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 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 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 reasonable 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 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 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 Utility.

/s/ DELOITTE & TOUCHE LLP

San Francisco, California

February 9, 2018

We have served as the Utility's auditor since 1999.

154

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 Corporation's and the Utility's respective principal executive officers and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

Management's Annual Report on Internal Control over Financial Reporting

Management of PG&E Corporation and the Utility 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 Report 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 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.

Changes in Internal Control Over Financial Reporting

There were no changes in internal control over financial reporting that occurred during the quarter ended December 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.

ITEM 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" at 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 Proxy 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 Proxy Statement relating to the 2018 Annual Meetings of Shareholders, which information 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 codes 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 President, 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' Audit 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 Utility 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

There were no material changes to the procedures described in PG&E Corporation's and the Utility's Joint Proxy Statement 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 Committee 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 2017," "Outstanding Equity Awards at Fiscal Year End - 2017," "Option Exercises and Stock Vested During 2017," "Pension Benefits – 2017," "Non-Qualified Deferred Compensation – 2017," "Potential Payment Upon Resignation, Retirement, Termination, Change in Control, Death, or Disability" and "Compensation of Non-Employee Directors – 2017 Director Compensation" in the Joint Proxy Statement relating to the 2018 Annual Meetings of Shareholders, 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 Corporation and the Utility is set forth under the 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 Shareholders, 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 Corporation'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, 1,426,371 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 granted 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 issuing 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 outstanding as of December 31, 2017.

(3) Represents 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 under 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 portion of such awards shall again be available for issuance under the 2014 LTIP.

For more information, see Note 5 of the Notes to the Consolidated Financial Statements in Item 8.

ITEM 13. Certain Relationships and Related Transactions, and Director Independence

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 relating 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 part of this report in Item 8:

Consolidated Statements of Income for the Years Ended December 31, 2017, 2016, 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, 2017, 2016, and 2015 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Balance Sheets at December 31, 2017 and 2016 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Cash Flows for the Years Ended December 31, 2017, 2016, and 2015 for each of PG&E Corporation and Pacific Gas and Electric Company.

Consolidated Statements of Equity for the Years Ended December 31, 2017, 2016, and 2015 for PG&E Corporation.

Consolidated Statements of Shareholders' Equity for the Years Ended December 31, 2017, 2016, 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 Accounting Firm (Deloitte & Touche LLP).

2. The following financial statement schedules are filed as part of this report:

Condensed Financial Information of Parent as of December 31, 2017 and 2016 and for the Years Ended December 31, 2017, 2016, 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, 2017, 2016, 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 Corporation amended as of December 16, 2016 (incorporated by reference to PG&E Corporation’s Form 10-K for the year ended December 31, 2016 (File No. 1-12609), Exhibit 3.3)
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 Company, 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 March 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, 2018 (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)

159

4.8	Eighth Supplemental Indenture, dated as of November 18, 2009, relating to the issuance of $550,000,000 aggregate principal 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 Gas 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 Electric 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 reference 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 Pacific 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)

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 Notes 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)
4.21	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. 1-2348), 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 (incorporated 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 (incorporated 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 Pacific 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)

161

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 Restated Credit Agreement, 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 joint 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, 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. Bank, 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 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 Restated Credit Agreement 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 Securities 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 lender, 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. Bank 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 March 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 Company'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 November 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) (incorporated 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)

162

10.9 *	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. and PG&E Corporation 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 10.04)
10.10*	Restricted Stock Unit Agreement 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 10.7)
10.11*	Restricted Stock Unit Agreement 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 10.7)
10.12*	Restricted Stock Unit Agreement between Anthony F. Earley, Jr. 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 Corporation 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. Earley, Jr. and PG&E Corporation 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 10.05)
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 customer affordability goals between Anthony F. Earley, Jr. and PG&E Corporation 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 customer 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 customer affordability 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 10.9)
10.20*	Performance Share Agreement between Anthony F. Earley, Jr. 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 10.5)
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 10.08)

163

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 (incorporated 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 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 10.7)
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 for 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 to PG&E Corporation's Form 10-Q for the quarter ended September 30, 2017 (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 to Pacific Gas and Electric Company's Form 10-Q for the quarter ended June 30, 2017 (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)

164

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 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 10.27)
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 December 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)

165

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 Pacific 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 reference 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 to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.01)
10.62*	Form of Restricted Stock Unit Agreement for 2016 grants 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 10.55)
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, 2015 (File No. 1-12609), Exhibit 10.4)
10.64*	Form of Restricted Stock Unit Agreement for 2014 grants 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 10.2)
10.65*	Form of Restricted Stock Unit Agreement for 2013 grants 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, 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)

166

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 to PG&E Corporation's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12609), Exhibit 10.02)
10.68*	Form of Performance Share Agreement subject to financial goals for 2016 grants 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 10.61)
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, 2015 (File No. 1-12609), Exhibit 10.5)
10.70*	Form of Performance Share Agreement subject to safety and customer affordability goals for 2017 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 June 30, 2017 (File No. 1-12609), Exhibit 10.03)
10.71*	Form of Performance Share Agreement subject to safety and customer affordability goals for 2016 grants 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 10.63)
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, 2015 (File No. 1-12609), Exhibit 10.6)
10.73*	Form of Performance Share Agreement for 2014 grants 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 10.3)
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 Corporation'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 reference to Pacific Gas and Electric Company's Form 10-K for the year ended December 31, 2004 (File No. 1-2348), Exhibit 10.41)

167

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
*		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.

169

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 Geisha J. Williams		NICKOLAS STAVROPOULOS 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 Geisha J. Williams	Chief Executive Officer and President (PG&E Corporation)	February 9, 2018
NICKOLAS STAVROPOULOS Nickolas Stavropoulos	President and Chief Operating Officer (Pacific Gas and Electric Company)	February 9, 2018
B. Principal Financial Officers		
JASON P. WELLS Jason P. Wells	Senior Vice President and Chief Financial Officer (PG&E Corporation)	February 9, 2018
DAVID S. THOMASON		

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	Vice President and Controller (PG&E Corporation)	February 9, 2018
David S. Thomason	Vice President, Chief Financial Officer, and Controller (Pacific Gas and Electric Company)	

D. Directors (PG&E Corporation and Pacific Gas and Electric Company, unless otherwise noted)

*LEWIS CHEW Lewis Chew	Director	February 9, 2018

170

*	FRED J. FOWLER Fred J. Fowler	Director	February 9, 2018
*	JEH C. JOHNSON Jeh C. Johnson	Director (PG&E Corporation only)	February 9, 2018
*	RICHARD C. KELLY Richard C. Kelly	Director Chair of the Board (PG&E Corporation)	February 9, 2018
*	ROGER H. KIMMEL Roger H. Kimmel	Director	February 9, 2018
*	RICHARD A. MESERVE Richard A. Meserve	Director	February 9, 2018
*	FORREST E. MILLER Forrest E. Miller	Director Chair of the Board (Pacific Gas and Electric Company)	February 9, 2018
*	ERIC D. MULLINS Eric D. Mullins	Director	February 9, 2018
*	ROSENDO G. PARRA Rosendo G. Parra	Director	February 9, 2018
*	BARBARA L. RAMBO Barbara L. Rambo	Director	February 9, 2018
*	ANNE SHEN SMITH Anne Shen Smith	Director	February 9, 2018
*	NICKOLAS STAVROPOULOS Nickolas Stavropoulos	Director (Pacific Gas and Electric Company only)	February 9, 2018
*	GEISHA J.WILLIAMS Geisha J. Williams	Director	February 9, 2018

*By:
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)
Comprehensive Income	$1,647	$1,391	$856
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

PG&E CORPORATION

SCHEDULE I — CONDENSED FINANCIAL INFORMATION OF PARENT – (Continued)

CONDENSED BALANCE SHEETS

(in millions)	Balance at December 31, 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

173

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, April, 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, 2017, 2016, and 2015

(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.

175

Pacific Gas and Electric Company

SCHEDULE II – CONSOLIDATED VALUATION AND QUALIFYING ACCOUNTS

For the Years Ended December 31, 2017, 2016, and 2015

(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.