PG&E Corp
Form 10-K
February 16, 2017

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, 2016

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

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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, or a smaller reporting company (as defined 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

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, 2016, the last business day of the most recently completed second fiscal quarter:

PG&E Corporation common stock	$31,807 million
Pacific Gas and Electric Company common stock	Wholly owned by PG&E Corporation

Common Stock outstanding as of February 7, 2017:

PG&E Corporation:	507,782,249 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 2017 Annual Meetings of Shareholders	Part III (Items 10, 11, 12, 13 and 14)

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UNITS OF MEASUREMENT

1 Kilowatt (kW)	=	One thousand watts
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 (GW)	=	One million kilowatts
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
1 Bcf	=	One billion cubic feet
1 MDth	=	One thousand decatherms

GLOSSARY

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

2016 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, 2016
AB	Assembly Bill
AFUDC	allowance for funds used during construction
ALJ	administrative law judge
ARO	asset retirement obligation
ASU	accounting standard update issued by the FASB (see below)
CAISO	California Independent System Operator
Cal Fire	California Department of Forestry and Fire Protection
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
CO2	carbon dioxide
CPUC	California Public Utilities Commission
CRRs	congestion revenue rights
DER	distributed energy resources
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
DTSC	Department of Toxic Substances Control
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
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

MOU	memorandum of understanding
NAV	net asset value
NDTCP	Nuclear Decommissioning Cost Triennial Proceedings
NEIL	Nuclear Electric Insurance Limited
NEM	net energy metering
NRC	Nuclear Regulatory Commission
NTSB	National Transportation Safety Board
OII	order instituting investigation
ORA	Office of Ratepayer Advocates
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSEP	pipeline safety enhancement plan
QF	qualifying facility
Regional Board	California Regional Water Quality Control Board, Lahontan Region

REITS	real estate investment trust
RFO	requests for offers
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
TE	transportation electrification
TO	transmission owner
TURN	The Utility Reform Network
Utility	Pacific Gas and Electric Company
VIE(s)	variable interest entity(ies)
Water Board	California State Water Resources Control Board

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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, 2016, PG&E Corporation and the Utility had approximately 24,000 regular employees, approximately 30 of which were employees of PG&E Corporation. Of the Utility's regular employees, approximately 14,000 are covered by collective bargaining agreements with the local chapters of three labor unions: the International Brotherhood of Electrical Workers ("IBEW"); the Engineers and Scientists of California ("ESC"); and the Service Employees International Union ("SEIU"). A new SEIU collective bargaining agreement was ratified in December 2016 and is effective August 1, 2016 through December 31, 2019. Two new agreements (Physical and Clerical) with IBEW and an agreement with ESC were ratified in 2016 and were retroactive to January 1, 2016. They 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 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 these websites is not part of this or any other report that PG&E Corporation or the Utility files with, or furnishes to, the SEC.

This Annual Report on 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 MD&A.

Regulatory 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 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 consists of five commissioners appointed by the Governor of California and confirmed by the California State Senate for staggered six-year terms. 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 electricity 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 both the gas and electric programs, 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. 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. In September 2016, the CPUC adopted improvements and refinements to its gas and electric safety citation programs. Specifically, the final decision refines the criteria for the SED to use in determining whether to issue a citation and the amount of penalty, sets an administrative limit of $8 million per citation issued, makes self-reporting voluntary in both gas and electric programs, adopts detailed criteria for the utilities to use to voluntarily self-report a potential violation, and refines other issues in the programs. The decision also merges the rules applicable to its gas and electric safety citation programs into a single set of rules that replaces the previous safety citation programs.

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 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 MD&A and Item 1A. Risk Factors below.)

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.

Ratemaking Mechanisms

The Utility’s rates for electricity and natural gas utility services are set at levels that are intended to allow the Utility to recover its costs of providing service including 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 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. 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, ensure that the Utility will fully collect its authorized base revenue requirements. 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 MD&A) within its authorized base revenue requirements.

Both electric and gas rates vary depending on seasons mostly due to the influence of weather. Electricity rates increase during the summer months (May – October) because of higher demand, driven by air conditioning loads, while gas service rates generally increase during the winter months (November – March) to account for the gas peak due to heating.

During 2016, 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 "Legislative and Regulatory Initiatives" in 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 – 2014 – 2015 Energy Efficiency Incentive Awards" in 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 electricity distribution, natural gas distribution, and Utility owned electricity 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. (For more information about the Utility's current GRC proceeding, see "Regulatory Matters –2017 General Rate Case" in 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 proceeding, the CPUC approves the annual revenue requirements for the first year (or "test year") of the GT&S period and typically determines annual increases in revenue requirements for attrition years of the GT&S 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, and union interests. (For more information, see "Regulatory Matters – 2015 Gas Transmission and Storage Rate Case" in 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 2017, 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%. 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. On February 25, 2016, the CPUC issued a decision granting a petition for modification filed by the Utility and the other California IOUs to clarify that the CPUC's previously adopted cost of capital adjustment mechanism would not be triggered for 2017.

On February 6, 2017, the Utility and other California IOUs entered into a MOU with the CPUC, ORA, and TURN to extend the next cost of capital application filing deadline two years to April 22, 2019 for the year 2020. To implement the MOU, on February 7, 2016, the IOUs, ORA, and TURN filed with the CPUC a petition for modification of prior CPUC decisions addressing cost of capital. If the petition for modification is approved as submitted it would reduce the Utility's ROE from 10.40% to 10.25% and reset the Utility's authorized cost of long-term debt and preferred stock beginning January 1, 2018. The Utility's current capital structure of 52% common equity, 47% long-term debt, and 1% preferred equity would remain unchanged. The Utility's cost of capital adjustment mechanism would not operate in 2017 but could operate in 2018 to change the cost of capital for 2019. 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. Concurrently with the petition for modification, the Utility and other California IOUs also sent a letter to the executive director of the CPUC requesting that the existing April 2017 filing due date for the 2018 cost of capital be deferred while the CPUC is considering the petition for modification. On February 13, 2017, the executive director of the CPUC granted the request. As extended, the Utility and the other California IOUs would file their next cost of capital applications 60 days after the effective date of the CPUC decision on the petition for modification, or April 20, 2017, whichever is later, if the CPUC does not grant the petition for modification.

The Utility expects that the CPUC may issue a decision in the first half of 2017. (For more information, see "Regulatory Matters –CPUC Cost of Capital" in 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 generally files 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: 1) by the CPUC in the Utility's retail electric rates and are collected from retail electric customers; and 2) by the CAISO in its Transmission Access Charges to wholesale customers. (For more information, see “Regulatory Matters – FERC Transmission Owner Rate Cases” in 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 electricity 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. The Utility’s most recent bundled customer procurement plan was approved in October 2015, and will remain in effect until the plan is 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 cost of replacement power procured due to unplanned outages at Utility owned generation facilities may be disallowed.

The Utility recovers its electricity 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 electricity rates more frequently if the forecasted aggregate over-collections or under-collections in the energy resource recovery account exceed 5% of its prior year electricity 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 electricity 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 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. (For more information, see "Legislative and Regulatory Initiatives" in MD&A.)

Electric Utility Operations

The Utility generates electricity and provides electricity 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 addition, in December 2016, the CPUC issued a final decision establishing a three-year EV program for the Utility to deploy up to 7,500 charging stations. (For more information, see "Legislative and Regulatory Initiatives" in 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 electricity 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 2016 represented by each major electricity resource, and further discussed below.

Total 2016 Actual Electricity Generated and Procured – 68,441 GWh (1):

	Percent of Bundled Retail Sales	
Owned Generation Facilities		
Nuclear	24.2 %	
Small Hydroelectric	1.3 %	
Large Hydroelectric	9.8 %	
Fossil fuel-fired	7.3 %	
Solar	0.5 %	
Total		43.1 %
Qualifying Facilities		
Renewable	2.6 %	
Non-Renewable	5.1 %	
Total		7.7 %
Irrigation Districts and Water Agencies		
Large Hydroelectric	0.5 %	
Total		0.5 %
Other Third-Party Purchase Agreements		
Renewable	28.4 %	
Large Hydroelectric	2.1 %	
Non-Renewable	4.8 %	
Total		35.3 %
Others, Net (2)		13.4 %

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.

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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.

As indicated below, the Utility's application and joint proposal to retire Diablo Canyon include a voluntary increase in the Utility's target for RPS-eligible resources to 55%, effective in 2031 through 2045, as compared to the state's goal of 50% renewables. (For more information, see "Legislative and Regulatory Initiatives" in MD&A.)

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 2016, 32.8% of the Utility's energy deliveries were from renewable energy sources, exceeding the annual RPS target of 23.3%. Approximately 28.4% of the renewable energy delivered to the Utility's customers was purchased from non-QF third parties. Additional renewable resources were provided by QFs (2.6%), the Utility's small hydroelectric facilities (1.3%), and the Utility's solar facilities (0.5%).

The total 2016 renewable deliveries shown above were comprised of the following:

Type	GWh	Percent of Bundled Retail Sales
Biopower	2,958	4.3%
Geothermal	3,705	5.4%
Small Hydroelectric	1,800	2.6%
Solar	8,598	12.6%
Wind	5,419	7.9%
Total	22,480	32.8%

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 RFOs to help meet its interim storage targets.

The Utility conducted an RFO in 2014. The Utility's 2014 energy storage target was 90 MW, some of which the Utility met through already existing projects, or projects anticipated to result from other CPUC proceedings. As a result of the 2014 RFO, 70 MW of transmission and distribution contracts have been approved by the CPUC. Contracts for 6MW were rejected by the CPUC, including a behind-the-meter project. Additionally, contracts for 13 MW were withdrawn by the Utility.

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The Utility's 2016 energy storage target is 120 MW. On November 30, 2016, the Utility issued its 2016 RFO. The Utility must submit all executed contracts from the 2016 RFO to the CPUC for approval by December 1, 2017. The Utility expects to increase the amount of storage it is attempting to procure in its 2016 RFO by the shortfall from the 2014 target.

Owned Generation Facilities. At December 31, 2016, 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	104	2,684
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		137	7,691

(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. (See "Diablo Canyon Nuclear Power Plant" in MD&A and Item 1A. Risk Factors.)

(2) The Utility's hydroelectric system consists of 107 generating units at 67 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 Five Points solar station (15 MW), Westside solar station (15 MW), Stroud solar station (20 MW), Huron solar station (20 MW), Cantua solar station (20 MW), Giffen solar station (10 MW), Gates solar station (20 MW), West Gates solar station (10 MW) and Guernsey solar station (20 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, 2016, the Utility owned approximately 18,400 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 64,600 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.

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. The CAISO has stated that the 2022 in-service date for the 70-mile line has been postponed, and 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 conducted a review of a number of local area low voltage transmission projects in the Utility’s service territory that were predominantly load forecast driven. As a result of the review, 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.

On March 29, 2026 the Utility entered into an agreement with TransCanyon, LLC, a joint venture between subsidiaries of Berkshire Hathaway Energy and Pinnacle West Capital Corporation, to jointly pursue competative transmission opportunities solicited by the CAISO. The Utility and TransCanyon intend to jointly engage in the development of future transmission infastructure and compete to develop, build, own and operate transmission projects approved by the CAISO.

Throughout 2016, the Utility upgraded several critical 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 electricity distribution network consists of approximately 142,000 circuit miles of distribution lines (of which approximately 20% are underground and approximately 80% are overhead), 59 transmission switching substations, and 606 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. In 2016 the Utility commenced operations in a new electric distribution control center facility in Concord, California; along with the existing distribution control centers in Rocklin and Fresno, California, these control centers form a key part of the Utility’s efforts to create a smarter, more resilient grid.

In 2016, the Utility continued to deploy its Fault Location, Isolation, and Service Restoration circuit technology which involves the rapid operation of smart switches to reduce the duration of customer outages. Another 89 circuits were outfitted with this equipment, bringing the total deployment to 789 of the Utility’s 3,200 distribution circuits. The Utility plans to continue performing work to improve the reliability and safety of its electricity distribution operations in 2017.

Electricity Operating Statistics

The following table shows certain of the Utility's operating statistics from 2014 to 2016 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 2016, 2015 and 2014.

	2016	2015	2014
Customers (average for the year)	5,349,691	5,311,178	5,276,025
Deliveries (in GWh) (1)	83,017	85,860	86,303
Revenues (in millions):			
Residential	$5,409	$5,032	$4,784
Commercial	5,396	5,278	5,141
Industrial	1,525	1,555	1,543
Agricultural	1,226	1,233	1,172
Public street and highway lighting	80	83	79
Other (2)	(68)	(84)	(172)
Subtotal	13,568	13,097	12,547
Regulatory balancing accounts (3)	297	560	1,109
Total operating revenues	$13,865	$13,657	$13,656
Selected Statistics:			
Average annual residential usage (kWh)	6,115	6,294	6,458
Average billed revenues per kWh:			
Residential	$0.1887	$0.1719	$0.1603
Commercial	0.1716	0.1640	0.1585
Industrial	0.0990	0.0973	0.0998
Agricultural	0.1814	0.1610	0.1516
Net plant investment per customer	$7,195	$6,660	$6,339

(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 a remittance of revenue to the Department of Water Resources ("DWR") (the Utility acts as a billing and collection agent on behalf of the DWR), 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 90% of core customers, representing nearly 78% of the annual core market demand, receive bundled natural gas service from the Utility.

The Utility does not provide procurement service to non-core customers, who must purchase their gas supplies from third-party suppliers. 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 fluctuated generally based on market conditions. During 2016, the Utility purchased approximately 307,100 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 2016.

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, 2016, the Utility's natural gas system consisted of approximately 42,800 miles of distribution pipelines, over 6,700 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. and TransCanada Foothills Pipe Lines Ltd., B.C. System. These companies' pipeline systems connect 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.)

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.

As of December 31, 2016 the Utility had installed 268 automatic and remote control shut-off valves on its gas transmission system, as specified in the eleventh of twelve safety recommendations made by the NTSB following its investigation of the San Bruno accident. The NTSB closed that recommendation in 2015. The final safety recommendation, considered open and acceptable by the NTSB, involves ensuring that all high consequence pipeline mileage in the Utility’s gas transmission system has been hydrostatically tested. As of December 31, 2016, the Utility has hydrostatically tested about 840 miles and completed the majority of this safety recommendation. The Utility currently plans to complete the NTSB recommendation by 2022 for the remaining approximately 28 aggregate pipeline miles (involving hundreds of primarily short pipeline segments that include tie-in pieces, fittings or smaller diameter off-takes from the larger transmission pipelines).

In addition, in 2016, the Utility inspected 260 miles of transmission pipeline using in-line inspection tools and upgraded an additional 107 miles of transmission pipeline to allow for the use in-line inspection tools, replaced 127 miles of distribution main, and completed the installation of over 25,000 line makers to more easily identify the locations of gas pipelines.

Natural Gas Operating Statistics

The following table shows the Utility's operating statistics from 2014 through 2016 (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 2016, 2015 and 2014.

	2016	2015	2014
Customers (average for the year)	4,442,379	4,415,332	4,394,283
Gas purchased (MMcf)	208,260	209,194	202,215
Average price of natural gas purchased	$1.83	$2.11	$4.09
Bundled gas sales (MMcf):			
Residential	149,483	144,885	143,514
Commercial	46,507	43,888	42,080
Total Bundled Gas Sales	195,990	188,773	185,594
Revenues (in millions):			
Bundled gas sales:			
Residential	$1,968	$1,816	$1,683
Commercial	439	403	419
Other	149	125	51
Bundled gas revenues	2,556	2,344	2,153
Transportation service only revenue	800	649	662
Subtotal	3,356	2,993	2,815
Regulatory balancing accounts	446	183	617
Total operating revenues	$3,802	$3,176	$3,432
Selected Statistics:			
Average annual residential usage (Mcf)	36	35	34
Average billed bundled gas sales revenues per Mcf:			
Residential	$13.10	$12.53	$11.72
Commercial	9.45	9.18	9.96
Net plant investment per customer	$2,808	$2,573	$2,468

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 which do not affirmatively elect to continue to receive electricity from a utility.

The Utility continues to provide transmission, distribution, metering, and billing services to direct access customers, although these customers can choose to obtain metering and billing services from their energy service provider. The CCA customers continue to obtain transmission, distribution, metering, and billing services from the Utility. In addition to collecting charges for transmission, distribution, metering, and billing services that it provides, the 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.

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 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, 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. 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.

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 Department of Toxic Substances Control, 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 electricity generation plants, natural gas pipeline operations, 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, CO2, sulfur dioxide (SO2), mono-nitrogen oxide (NOx), particulate matter, and other GHG emissions.

In December 2009, the EPA concluded that GHG emissions contribute to climate change and issued a finding that GHG emissions cause or contribute to air pollution that endangers public health and welfare. In May 2014, the U.S. Global Change Research Program (a confederation of the research arms of thirteen federal departments and agencies) released its third National Climate Assessment, which stated that the global climate is changing and that impacts related to climate change are already evident in many sectors and are expected to become increasingly disruptive across the nation throughout this century and beyond.

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.

In August 2015, the EPA published final regulations under section 111(b) of the Clean Air Act to control CO2 emissions from new fossil fuel-fired power plants. While these regulations do not affect the Utility's existing power plants, the regulations impose emission limitations on fossil fuel-fired power plants constructed after January 8, 2014 and will affect the design, construction, operation and cost of such power plants.

In August 2015, the EPA also published final regulations under section 111(d) of the Clean Air Act to control CO2 emissions from existing fossil fuel-fired power plants. These regulations are designed to reduce power plant CO2 emissions on a national basis by as much as 32% by 2030, compared with 2005 levels. States were required to submit final plans to comply with these regulations by September 2016, but were permitted to request an extension to file such plans until September 2018. It is uncertain whether and how these federal regulations will ultimately impact California, since existing state regulation currently requires, among other things, the gradual reduction of state-wide GHG emissions to 40% below 1990 levels by 2030. Following publication of the EPA's regulations, in October 2015 West Virginia and several other states and parties challenged the EPA's section 111(d) regulations in the United States Court of Appeals for the District of Columbia Circuit and petitioned the Court to stay the regulations pending review of the appeal on the merits. The D.C. Circuit denied the request for stay but in February 2016, the United States Supreme Court granted a stay of the section 111(d) regulations pending review of the appeal by the D.C. Circuit. The Supreme Court's decision may affect the nature, extent and timing of implementation of these regulations. As described below, the Utility expects all costs and revenues associated with the state-wide, comprehensive cap-and-trade program to be passed through to customers.

With the change in federal administration from President Barack Obama to President Donald Trump, there is significant uncertainty with regard to what further actions may occur regarding climate change at the federal level. The new administration has indicated that it intends to revoke the Clean Power Plan regulations and possibly withdraw from international efforts to combat climate change. 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, pending further review. It is assumed that the new administration also will take action to suspend all climate related regulatory and funding activities. In light of the potential 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 electricity 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. Additionally, Senate Bill 32 (2016) requires that CARB ensure a 40% reduction in greenhouse gases by 2030 compared to 1990 levels. CARB is currently considering regulatory amendments to the cap-and-trade program to extend the program's authority 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 Mitigation and Adaptation Strategies. During 2016, the Utility continued its programs to develop strategies 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 adapt to the likely impacts of climate change on the Utility's future operations, including forming an officer-level coordinating committee to govern and oversee the Utility's activities. The Utility regularly reviews the most relevant scientific literature on climate change such as sea level rise, temperature changes, rainfall and runoff patterns, and wildfire risk, to help the Utility identify and evaluate climate change-related risks and develop the necessary adaptation strategies. The Utility maintains emergency response plans and procedures to address a range of near-term risks, including extreme storms, heat waves and wildfires 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.

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. The Utility's vegetation management activities also reduce the risk of wildfire impacts on electric and gas facilities. 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.

Notwithstanding the current high snowpack, 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 2015 totaled more than 54 million metric tonnes of CO–2 equivalent, two-thirds of which came from customer natural gas use. The following table shows the 2015 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 equivalent)
Fossil Fuel-Fired Plants (1)	2,875,176
Natural Gas Compressor Stations and Storage Facilities (2)	362,472
Distribution Fugitive Natural Gas Emissions	676,458
Customer Natural Gas Use (3)	43,022,557

(1) Includes nitrous oxide and methane emissions from the Utility's generating stations.

(2) Including, but not limited to, compressor stations and storage facilities emitting more than 25,000 metric tonnes of CO2 equivalent annually.

(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. This figure does not represent the Utility's compliance obligation under AB 32, which will be equivalent to the above reported value less the fuel that is delivered to covered entities, as calculated by the CARB.

The following table shows the Utility's third-party-verified CO2 emissions rate associated with the electricity delivered to customers in 2015 as compared to the national average for electric utilities:

	Amount (pounds of CO2 per MWh)
U.S. Average (1)	1,143
Pacific Gas and Electric Company (2)	405

(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 40% of the Utility's delivered electricity in 2015. PG&E Corporation and the Utility also publish air emissions data in their annual Corporate Responsibility and Sustainability Report.

	2015	2014
Total NOx Emissions (tons)	160	141
NOx Emissions Rate (pounds/MWh)	0.01	0.01
Total SO2 Emissions (tons)	17	14
SO2 Emissions Rate (pounds/MWh)	0.0011	0.0010

Water Quality

On May 19, 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 Fourth 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. The Utility's Diablo Canyon operations must be in compliance with the California Water Board's policy by December 31, 2024.

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025, and replace it with a GHG-free portfolio of energy efficiency, renewables and energy storage. As a result of the planned retirement, the California Water Board will no longer need to address alternative compliance measures for Diablo Canyon. Beginning in 2017, as required under the policy, the Utility will pay an annual interim mitigation fee until operations cease in 2024 and 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 Water 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 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 2016, the Utility has been awarded an additional $99 million through these annual submissions, including $28 million for costs incurred between June 1, 2014 and May 31, 2015. The claim for the period June 1, 2015 through May 31, 2016 is currently under review by the DOE. These proceeds are being refunded to customers through rates. The settlement agreement, as amended, does not address costs incurred for spent fuel storage beyond 2016; an extension of the agreement for costs through 2019 is pending DOJ approval. Costs beyond 2016 could be subject to future litigation. 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.

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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, results of operations, financial condition, and stock price.

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

PG&E Corporation's and the Utility's financial condition, results of operations, 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 a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its 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, 2016, 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 involving approximately 1,950 individual plaintiffs representing approximately 950 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 inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility believes that it is probable that it will incur a loss of at least $750 million for all potential damages described above. 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 approximately $900 million. Such insurance coverage is subject to the terms and limitations of the available policies and may not be sufficient to cover the Utility's ultimate liability.

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 and results from the ongoing mediation and settlement process, management estimates and assumptions regarding the financial impact of the Butte fire may change. 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 the results of operations during the period such change occurred.

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. (For more information, see "Enforcement and Litigation Matters" in Item 7. MD&A and in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

PG&E Corporation's and the Utility's future financial results may 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 also could incur material costs and fines in connection with future investigations, citations, audits, or enforcement actions.

The Utility could incur material charges, including fines and other penalties, in connection with a potential settlement or litigated outcome of the CPUC's investigation of the Utility's compliance with the CPUC's rules regarding ex parte communications. While on October 14, 2016, the Cities of San Bruno and San Carlos, ORA, the SED, TURN, and the Utility submitted a status report to the CPUC which proposed an update to the framework for resolving the proceeding and included a total of 164 communications in the scope of the proceeding, the Utility expects that the other parties may argue that the number of violations exceeds the 164 communications referenced in the status report either because a single communication may have violated more than one rule or because they believe some of the material provided during discovery constitutes impermissible ex parte communications. The Utility expects to contest many of these assertions. If the matter does not settle, the CPUC will determine which communications included within the scope of the proceeding were in violation of its rules. The CPUC will also determine whether to impose penalties or other remedies, as a result of a potential settlement or otherwise. The CPUC can impose fines up to $50,000 for each violation, and up to $50,000 per day if the CPUC determines that the violation was continuing. The CPUC has wide discretion to determine the amount of penalties based on the totality of the circumstances, including such factors as how many days each violation continued; the gravity of the violations; the type of harm caused by the violations and the number of persons affected; and the good faith of the entity charged in attempting to achieve compliance, after notification of a violation. The CPUC is also required to consider the appropriateness of the amount of the penalty to the size of the entity charged. The CPUC has historically exercised 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 the discussion under the heading "Regulatory Matters" in MD&A.)

The Utility also is a target of a number of investigations and government requests for information. 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. In addition, in October 2016, the Utility received a grand jury subpoena and letter from the U.S. Attorney for the Northern District of California advising that the Utility is a target of a federal investigation regarding possible criminal violations of the Migratory Bird Treaty Act and conspiracy to violate the act. The Utility was also contacted by certain other federal agencies with requests for information. While the Utility believes that these requests for information are routine, their outcome is uncertain. The Utility also is unable to predict the outcome of pending investigations, including whether any charges will be brought against the Utility.

If these investigations or requests for information result in enforcement action against the Utility, the Utility could incur additional fines or penalties or suffer negative consequences described above in the immediately preceding risk factor. In addition, a negative outcome in any of these investigations or future enforcement actions may negatively affect the outcome of future ratemaking and regulatory proceedings; 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.

The Utility may incur fines and penalties in connection with the Utility's efforts to identify and remove encroachments from transmission pipeline rights of way and the Penalty Decision. The Penalty Decision requires the SED to review the Utility's gas transmission operations (including the Utility's compliance with the remedies ordered by the 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. In addition, although PG&E Corporation and the Utility do not currently face the possibility of fines or penalties in the first phase of the CPUC's pending investigation into the Utility's safety culture since it has been categorized as rate setting, it is uncertain how a next phase, if any, would be categorized. (See the discussion under the heading "Regulatory Matters" in MD&A.)

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. CPUC staff could 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 results.

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.

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 Utility has decided not to appeal the convictions.

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 is required to retain a third-party monitor. The goal of the monitorship will be to prevent the criminal conduct with respect to gas pipeline transmission safety that gave rise to the conviction. To that end, the goal of the monitor will be to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of the gas transmission pipeline system, performs appropriate integrity management assessments on its gas transmission pipelines, and maintains an effective ethics and compliance program and safety related incentive program.

After an initial assessment is conducted and an initial report is prepared by the monitor, the monitor will prepare reports on a semi-annual basis setting forth the monitor's continued assessment and making recommendations consistent with the goals and scope of the monitorship. The Utility expects that the monitor will be retained before the end of the second quarter of 2017.

At December 31, 2016, PG&E Corporation and the Utility's Consolidated Balance Sheets included a $3 million accrual in connection with this matter. 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 the monitor's compensation or costs resulting from recommendations of the monitor).

Also, in September 2015, the Utility was notified that the DOI had initiated an inquiry into whether the Utility should be suspended or debarred from entering into federal procurement and non-procurement contracts and programs citing the 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. The agreement will be effective until superseded by an amended agreement or determination. The agreement also provides that the DOI is still conducting a review to determine whether the Utility has an effective compliance and ethics program and that the DOI is required to use its best efforts to complete its review before the end of 2017. If the DOI determines that the Utility's 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 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. As discussed under the heading "Regulatory Matters" in Item 7. MD&A, the SED continues evaluating PG&E Corporation's and the Utility's organizational culture and governance in the CPUC's pending investigation to examine the Utility's safety culture.

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 Utility's reputation (especially as a result of the Utility's conviction in the federal criminal trial), 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.

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 changes in customer demand for the Utility's electricity and natural gas services.

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, 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's ability to recover its costs also may be affected by the economy and its impact on the Utility's customers. For example, a sustained downturn or sluggishness in the economy could reduce the Utility's sales to industrial and commercial customers or the level of uncollectible bills could increase. Although the Utility generally recovers its costs through rates, regardless of sales volume, rate pressures increase when the costs are borne by a smaller sales base.

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.

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 costs are unreasonably above market.

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 net energy metering ("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. In January 2016, the CPUC adopted new NEM rules and rates. The new rules and rates became effective for new NEM customers of the Utility in December 2016. New NEM customers will be required to pay an interconnection fee, will go on time of use rates, and will be required to pay some non-bypassable charges to help fund some of the costs of low income, energy efficiency, and other programs that other customers pay. However, the resulting rules will still put upward rate pressure on remaining customers, and remove the cap on the number of NEM customers. 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 states 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 capital investment would likely decline as well, in turn 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 adversely impact PG&E Corporation's and the Utility's financial results.

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 cost-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. 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 results could be materially affected.

Risks Related to Liquidity and Capital Requirements

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, 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 the pending CPUC investigations and ratemaking proceedings. If PG&E Corporation's or the Utility's credit ratings were downgraded 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, 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, volatility in electricity or natural gas prices, 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 7. MD&A. 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.

If the Utility were unable to access the capital markets, it could be required to decrease or suspend dividends to PG&E Corporation and PG&E Corporation could be required to contribute capital to the Utility to enable the Utility to fulfill its obligation to serve. To maintain PG&E Corporation's dividend level in these circumstances, PG&E Corporation would be further required to access the capital or credit markets. PG&E Corporation may need to decrease or discontinue its common stock dividend if it is unable to access the capital or credit markets on reasonable terms.

PG&E Corporation's ability to meet its debt service and other financial obligations and to pay dividends on its common stock depends on the Utility's earnings and cash flows.

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 its obligation to serve customers, to pay principal and interest on outstanding debt, to pay preferred stock dividends, 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 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 terms of the probation or monitorship, the pending CPUC investigations, or other 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 EPS. (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 was 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.

PG&E Corporation's and the Utility's ability to pay dividends also could be affected by financial covenants contained in their respective credit agreements that require each company to maintain a ratio of consolidated total debt to consolidated capitalization of at most 65%.

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 results. The Utility's insurance may not be sufficient to cover losses caused by an operating failure or catastrophic event, or may not become available at a reasonable cost, or available at all.

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. 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;

- 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), and the failure to respond effectively to a catastrophic event;

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;

severe weather events such as storms, tornadoes, floods, drought, earthquakes, tsunamis, wild land and other fires, pandemics, solar events, electromagnetic events, or other natural disasters;

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 damage 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.

In particular, the Utility may incur material liability in connection with the Butte fire. (See "PG&E Corporation and the Utility may incur material liability in connection with Butte Fire" above.) Additionally, on January 12, 2017, a residential structure fire occurred in Yuba City, California resulting in the collapse of the house and injuries to two persons inside the house. The CPUC, a third-party engineering firm, and local fire and police officials are investigating the origin and cause of the incident. The Utility may incur material costs, including as a result of these investigations or any proceedings that could be commenced in connection with this incident.

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 results. 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.

Further, 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 and takings as a result of the design, construction and maintenance of utility facilities, including its electric transmission lines. As a result of the strict liability standard applied to wildfires, recent losses recorded by insurance companies, the risk of increase of wildfires including as a result of the ongoing drought, 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.

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, or cash flows could be materially affected.

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

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

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

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

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

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

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

The operation of the Utility's nuclear generation facilities exposes it to potentially significant liabilities from environmental, health and financial risks, such as risks relating to the storage, handling and disposal of spent nuclear fuel, and the release of radioactive materials caused by a nuclear accident, seismic activity, natural disaster, or terrorist act. If the Utility incurs losses that are either not covered by insurance or exceed the amount of insurance available, such losses could have a material effect on PG&E Corporation's and the Utility's financial results. In addition, the

Utility may be required under federal law to pay up to $255 million of liabilities arising out of each nuclear incident occurring not only at the Utility's Diablo Canyon facility but at any other nuclear power plant in the United States. (See Note 13 of the Notes to the Consolidated Financial Statements in Item 8.)

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

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. The Utility currently estimates that the additional cost of the employee retention program and the employee retraining and development program will be approximately $350 million. The Joint Proposal seeks confirmation from the CPUC that these costs will be recovered through the Utility's nuclear decommissioning electric rates. The employee retention and retraining and development programs are subject to bargaining with the Utility's labor unions. The Utility will also incur costs in connection with an employee severance program. The severance program was previously approved by the CPUC in prior nuclear decommissioning ratemaking proceedings.

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 before the licenses expire in 2024 and 2025. At December 31, 2016, the Utility's unrecovered investment in Diablo Canyon was $1.7 billion.

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

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

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

Risks Related to Environmental Factors

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, 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.) 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.

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The Utility's future operations may be affected by climate change that may have a material impact on PG&E Corporation's and the Utility's financial condition, results of operations, and cash flows.

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. While snowpack in the Sierra Nevada Mountains has been at higher than normal levels this winter, California has experienced ongoing drought in the past. If temperatures and the levels of precipitation in the Utility's service territory continue to change, that could impact the levels of snowpack in the Sierra Nevada Mountains. 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, increasing temperatures and lower levels of precipitation could increase the occurrence of wildfires in the Utility's service territory causing damage to the Utility's facilities or the facilities of third parties on which the Utility relies to provide service, damage to third parties for loss of property, personal injury, or loss of life. In addition, flooding caused by rising sea levels could damage the Utility's facilities, including hydroelectric assets such as dams and canals, and the electric transmission and distribution assets. The Utility could incur substantial costs to repair or replace facilities, restore service, 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, and cash flows could be materially affected.

Other Risk Factors

PG&E Corporation's and the Utility's financial results could be materially affected as a result of political and legislative developments.

The Utility's financial results could be materially affected as a result of the recent change in federal administration from President Barack Obama to President Donald Trump. For example, the new administration has indicated tax reform as a priority. Tax reform outlines produced by both President Trump and the Tax Reform Task Force include proposals related to federal tax rates, deductions for state income taxes (and potentially property tax), interest expense deduction, capital expenditure deduction, and expensing plant. It is unclear what tax reform may be ultimately adopted. It is generally expected that a tax reform bill will be introduced in early 2017.

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 results 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 results 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.

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 167,000 acres of land, including approximately 140,000 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 2018, 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.

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

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 that could have led to or contributed to the natural gas explosion that occurred in the City of San Bruno, California on September 9, 2010. In January 2016, the CPUC closed the investigative proceedings. The total penalty included (1) a $300 million fine, (2) a one-time $400 million bill credit to the Utility's natural gas customers, (3) $850 million to fund pipeline safety projects and programs, and (4) remedial measures that the CPUC estimates will cost the Utility at least $50 million.

The Utility refunded the $400 million to its customers in the second quarter of 2016 and paid the $300 million fine in the third quarter of 2015. On December 1, 2016, the CPUC approved a final phase two decision in the Utility's 2015 GT&S rate case, which applies $689 million of the $850 million penalty to capital expenditures. The Utility is precluded from including these capital costs in rate base. The final phase two decision also approves the Utility's list of programs and projects that meet the CPUC's definition of "safety related," the costs of which are to be funded through the $850 million penalty. For more information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

Federal Criminal Trial

On June 14, 2016, a federal criminal trial against the Utility began in the United States District Court for the Northern District of California, in San Francisco, on 12 felony counts alleging that the Utility knowingly and willfully violated minimum safety standards under the Natural Gas Pipeline Safety Act relating to record-keeping, pipeline integrity management, and identification of pipeline threats, and one felony count charging that the Utility obstructed the NTSB investigation into the cause of the San Bruno accident. On July 26, 2016, the court granted the government's motion to dismiss one count alleging that the Utility knowingly and willfully failed to retain a strength test pressure record with respect to a distribution feeder main, thereby reducing the total number of counts from 13 to 12.

On August 9, 2016, the jury returned its verdict. The jury acquitted the Utility on all six of the record-keeping allegations but found the Utility guilty on six felony counts that include 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 sentencing 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 Utility has decided not to appeal the convictions. 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 is required to retain a third-party monitor. The goal of the monitorship will be to prevent the criminal conduct with respect to gas pipeline transmission safety that gave rise to the conviction. To that end, the goal of the monitor will be to help ensure that the Utility takes reasonable and appropriate steps to maintain the safety of the gas transmission pipeline system, performs appropriate integrity management assessments on its gas transmission pipelines, and maintains an effective ethics and compliance program and safety related incentive program.

After an initial assessment is conducted and an initial report is prepared by the monitor, the monitor will prepare reports on a semi-annual basis setting forth the monitor's continued assessment and making recommendations consistent with the goals and scope of the monitorship. The Utility expects that the monitor will be retained before the end of the second quarter of 2017. For more information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8 and Item 1A. Risk Factors.

Litigation Related to the San Bruno Accident and Natural Gas Spending

As of December 31, 2016, there were seven purported derivative lawsuits seeking recovery on behalf of PG&E Corporation and the Utility for alleged breaches of fiduciary duty by officers and directors, among other claims.

Four of the complaints were consolidated as the San Bruno Fire Derivative Cases and are pending in the Superior Court of California, County of San Mateo. The remaining three cases are Tellardin v. Anthony F. Earley, Jr.,. et al., Iron Workers Mid-South Pension Fund v. Johns, et al., and Bushkin v. Rambo et al.

On December 8, 2015, the California Court of Appeal issued a writ of mandate to the Superior Court of California, San Mateo County, ordering the court to stay all proceedings in the four consolidated San Bruno Fire Derivative Cases pending conclusion of the federal criminal proceedings against the Utility. On November 16, 2016, counsel in the four consolidated San Bruno Fire Derivative cases, as well as counsel in the Tellardin action, appeared for a status conference in the San Mateo Superior Court. The court reaffirmed that all proceedings in these actions were stayed until the conclusion of the Utility's federal criminal proceeding, at which point they were directed to meet and confer and report back to the court. The parties completed a mediation session on December 8-9, 2016 and continue discussions about the potential resolution of the matter. These actions remain stayed.

Bushkin v. Rambo et al., pending in the United States District Court for the Northern District of California, has been designated by the plaintiff as related to the pending shareholder derivative suit Iron Workers Mid-South Pension Fund v. Johns, et al., discussed below. The plaintiff in the Bushkin lawsuit has agreed that this case should be stayed pending conclusion of the federal criminal trial against the Utility and, on May 3, 2016, the judge entered a stipulated order staying the case. The order also provides that the parties should meet and confer within 30 days after the criminal trial concludes and provide the court a status update. Despite the stay of his complaint, on June 20, 2016 the Bushkin plaintiff filed a petition in the Superior Court of California, San Francisco County, seeking to enforce the plaintiff's claimed right as a shareholder to inspect certain PG&E Corporation accounting books and records pursuant to section 1601 of the California Corporations Code. On July 25, 2016, PG&E Corporation filed a motion to stay plaintiff's petition until the appellate stay of the San Bruno Fire Derivative Cases has been lifted, or, in the alternative, a demurrer asking the court to dismiss plaintiff's petition. On August 29, 2016, the San Francisco Superior Court granted PG&E Corporation's motion, and indicated that plaintiff's petition was stayed pending resolution of the criminal matter against the Utility. On January 13, 2017, the parties submitted a joint case management statement advising the court that, because the Utility had not yet been sentenced, the case should remain stayed until at least March 10, 2017, when the parties will advise the court of further developments. While the Utility was sentenced in the federal criminal proceeding on January 26, 2017, this matter remains stayed until at least March 10, 2017.

The Iron Workers action pending in the United States District Court for the Northern District of California has been stayed pending the resolution of the San Bruno Fire Derivative Cases. On May 5, 2016, the court ordered the parties to meet and confer within 30 days after the criminal trial concludes and provide the court a status update. At the court's request, on August 22, 2016, the parties filed a statement requesting that the case continue to be stayed until resolution of the San Bruno Fire Derivative Cases. On August 31, 2016, the court set a case management conference for September 30, 2016, and requested the parties to file a joint case management conference statement by September 23, 2016. On September 30, 2016, the court decided to continue the stay pending the resolution of the federal criminal proceeding against the Utility and ordered the parties to submit a joint status report on or before March 15, 2017. This matter remains stayed until at least March 15, 2017.

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

Butte Fire Litigation

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 a press release also issued on April 28, 2016, Cal Fire indicated that it will seek to recover firefighting costs in excess of $90 million from the Utility.

On May 23, 2016, individual plaintiffs filed a master complaint against the Utility and its 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, 2016, 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 involving approximately 1,950 individual plaintiffs representing approximately 950 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 inverse condemnation and negligence theories of liability. The number of individual complaints and plaintiffs may increase in the future.

The Utility continues mediating and settling cases. The next case management conference is scheduled for March 2, 2017.

In connection with this matter, the Utility may be liable for property damages, interest, and attorneys' fees without having been found negligent, through the theory of inverse condemnation. In addition, the Utility may be liable for fire suppression costs, personal injury damages, and other damages if the Utility were found to have been negligent. The Utility believes it was not negligent; however, there can be no assurance that a court or jury would agree with the Utility. The Utility believes that it is probable that it will incur a loss of at least $750 million for all potential damages described above. This amount is based on assumptions about the number, size, and type of structures damaged or destroyed, the contents of such structures, the number and types of trees damaged or destroyed, as well as assumptions about personal injury damages, attorneys' fees, fire suppression costs, and other damages that the Utility could be liable for under the theories of inverse condemnation and/or negligence.

For additional information, see "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

Other Enforcement Matters

Fines may be imposed, or other regulatory or governmental enforcement action could be taken, with respect to the Utility's self-reports of noncompliance with electric and natural gas safety regulations, prohibited ex parte communications between the Utility and CPUC personnel, and other enforcement matters. See "Enforcement and Litigation Matters" in Note 13 of the Notes to the Consolidated Financial Statements in Item 8.

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.

Subsequently, the California State Water Resources Control Board adopted a Once-Through Cooling Water Policy in May 2010 which requires Diablo Canyon to be in compliance with the policy by December 2024 and allows for alternative compliance measures at nuclear power plants.

On June 20, 2016, the Utility entered into a joint proposal with certain parties to retire Diablo Canyon at the expiration of its current operating licenses in 2024 and 2025 and replace it with a GHG-free portfolio of energy efficiency, renewables and energy storage. The Utility expects that the State Board's OTC Policy and its decision to retire Diablo Canyon will affect the terms of a final settlement agreement between the Utility, the Central Coast Water Board and the California Attorney General's Office. Also, as required under the State Board's OTC Policy, beginning in 2017, the Utility will pay an annual interim mitigation fee until operations cease at the end of the current licenses.

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

Venting Incidents in San Benito County

As part of its regular maintenance and inspection practices for its natural gas transmission system, the Utility performs in-line inspections of pipelines using devices called "pigs" that travel through the pipeline to inspect and clean the walls of the pipe. When in-line inspections are performed, natural gas in the pipeline must be released or vented at the pipeline station where the device is removed. In February 2014, the Utility conducted an in-line inspection of a natural gas transmission pipeline that traverses San Benito County and vented the natural gas at the Utility's transmission station located in Hollister, which is next to an elementary school. The Utility vented the natural gas during school hours on three occasions that month. After being informed of the venting by the local air district, the San Benito County district attorney notified the Utility in December 2014 that it was contemplating bringing a civil legal action against the Utility for violation of Health and Safety Code section 41700, which prohibits discharges of air contaminants that cause a public nuisance. In January 2017, the Utility and the district attorney reached an agreement on a stipulated judgement that resolves the matter. The stipulated judgment includes a fine of approximately $175,000. In addition, a $75,000 fine will be held in abeyance for 5 years, and would be payable to the San Benito County district attorney in case of non-compliance with certain remedial requirements of the stipulated judgment. The stipulated judgment was executed by the court on January 27, 2017.

Transformer Oil Release in Sonoma County

During a rain storm in February 2015, transformer oil was released into an underground vault in the City of Santa Rosa, in Sonoma County, while a Utility crew was replacing a broken transformer. Following further rains, the oil released from the vault and reached a nearby creek. The event was investigated by Santa Rosa Fire Department, the local environmental enforcement authority, and later referred to the Sonoma County District Attorney's Office. In May 2016, the District Attorney informed the Utility that it would seek penalties and costs in excess of $100,000 for alleged violations of several sections of the California Health and Safety and California Government codes which prohibit unauthorized spills or releases of oil into waters of the state and require that releases be reported to the Office of Emergency Services. In November 2016, the Utility and the Sonoma County district attorney reached an agreement on a stipulated judgment that resolves the matter. The stipulated judgment includes a fine of $80,000, reimbursement of enforcement costs of $40,000, and injunctive provisions requiring improvements to the Utility's vault dewatering procedure and training. In November 2016, the court approved the stipulated judgment.

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 16, 2017. 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
Anthony F. Earley, Jr. (2)	67	Chairman of the Board, Chief Executive Officer, and President, PG&E Corporation	September 13, 2011 to present
		Executive Chairman of the Board, DTE Energy Company	October 1, 2010 to September 12, 2011
Nickolas Stavropoulos (2)	58	President, Gas	September 15, 2015 to present
		President, Gas Operations	August 17, 2015 to September 15, 2015
		Executive Vice President, Gas Operations	June 13, 2011 to August 16, 2015

Geisha J. Williams (2)	55	President, Electric	September 15, 2015 to present
		President, Electric Operations	August 17, 2015 to September 15, 2015
		Executive Vice President, Electric Operations	June 1, 2011 to August 16, 2015
Jason P. Wells	39	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	52	Executive Vice President, Corporate Services and Human Resources, PG&E Corporation	August 17, 2015 to present
		Senior Vice President, Human Resources, PG&E Corporation and Pacific Gas and Electric Company	April 16, 2007 to August 16, 2015
Karen A. Austin	55	Senior Vice President and Chief Information Officer	June 1, 2011 to present
		President, Consumer Electronics, Sears Holdings	February 2009 to May 2011

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Desmond A. Bell (3)	54	Senior Vice President, Safety and Shared Services	January 1, 2012 to present
Helen A. Burt (3)	60	Senior Vice President, External Affairs and Public Policy, PG&E Corporation and Pacific Gas and Electric Company	September 30, 2015 to present
		Senior Vice President, Corporate Affairs, PG&E Corporation	September 18, 2014 to September 30, 2015
		Senior Vice President and Chief Customer Officer	February 27, 2006 to September 17, 2014
Loraine M. Giammona	49	Senior Vice President and Chief Customer Officer	September 18, 2014 to present
		Vice President, Customer Service	January 23, 2012 to September 17, 2014
		Regional Vice President, Customer Care, Comcast Cable	November 2002 to January 2012
Edward D. Halpin	55	Senior Vice President, Generation and Chief Nuclear Officer	March 28, 2016 to present
		Senior Vice President, Power Generation and Chief Nuclear Officer	September 8, 2015 to March 27, 2016
		Senior Vice President and Chief Nuclear Officer	April 2, 2012 to September 8, 2015
		President, Chief Executive Officer and Chief Nuclear Officer, South Texas Project Nuclear Operating Company	December 2009 to March 2012
Patrick M. Hogan	53	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	58	Senior Vice President and Chief Ethics and Compliance Officer, PG&E Corporation and Pacific Gas and Electric Company	May 18, 2015 to present
		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	44	Senior Vice President, Regulatory Affairs	September 18, 2014 to present
		Vice President, Customer Energy Solutions	May 15, 2011 to September 17, 2014

		Vice President, Integrated Demand Side Management	July 1, 2010 to May 14, 2011
Dinyar B. Mistry	55	Senior Vice President, Human Resources and Chief Diversity Officer, PG&E Corporation and Pacific Gas and Electric Company	February 1, 2017 to present

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		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
Hyun Park (4)	55	Senior Vice President and General Counsel, PG&E Corporation	November 13, 2006 to present
Jesus Soto, Jr.	49	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
		Vice President, Operations Services, El Paso Pipeline Group	May 2007 to May 2012
Fong Wan	55	Senior Vice President, Energy Policy and Procurement	September 8, 2015 to present
		Senior Vice President, Energy Procurement	October 1, 2008 to September 8, 2015
David S. Thomason	41	Vice President, Chief Financial Officer, and Controller	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
		Director, Planning, Forecasting and Reporting	October 3, 2011 to August 31, 2012

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

(2) On November 14, 2016, the Board of Directors of PG&E Corporation elected Mr. Earley to the role of Executive Chair of the Board of PG&E Corporation and Ms. Williams to the role of Chief Executive Officer and President of PG&E Corporation, both effective March 1, 2017. Also on November 14, 2016, the Board of Directors of the Utility

elected Mr. Stavropoulos as President and Chief Operating Officer of the Utility effective March 1, 2017.

(3) Mr. Bell and Ms. Burt will step down from their positions effective March 1, 2017.

(4) Mr. Park will step down from his position effective March 1, 2017 but is expected to remain with PG&E Corporation until September 1, 2017.

PART II

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

As of February 7, 2017, there were 56,835 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 PG&E Corporation’s Consolidated Statements of Equity, the Utility’s Consolidated Statements of Shareholders’ Equity, and Note 5 of the Notes to the Consolidated Financial Statements in Item 8 and in “Liquidity and Financial Resources – Dividends” in Item 7 below.

Sales of Unregistered Equity Securities

PG&E Corporation made equity contributions to the Utility totaling $95 million during the quarter ended December 31, 2016. PG&E Corporation did not make any sales of unregistered equity securities during 2016 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, 2016, 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, 2016, the Utility did not redeem or repurchase any shares of its various series of preferred stock outstanding.

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ITEM 6. SELECTED FINANCIAL DATA

(in millions, except per share amounts)	2016	2015	2014	2013	2012
PG&E Corporation					
For the Year					
Operating revenues	$17,666	$16,833	$17,090	$15,598	$15,040
Operating income	2,177	1,508	2,450	1,762	1,693
Net income	1,407	888	1,450	828	830
Net earnings per common share, basic (1)	2.79	1.81	3.07	1.83	1.92
Net earnings per common share, diluted	2.78	1.79	3.06	1.83	1.92
Dividends declared per common share (2)	1.93	1.82	1.82	1.82	1.82
At Year-End					
Common stock price per share	$60.77	$53.19	$53.24	$40.28	$40.18
Total assets (3)	68,598	63,234	60,228	55,693	52,530
Long-term debt (excluding current portion) (3)	16,220	15,925	15,151	12,805	12,598
Capital lease obligations (excluding current portion) (4)	31	49	69	90&#	